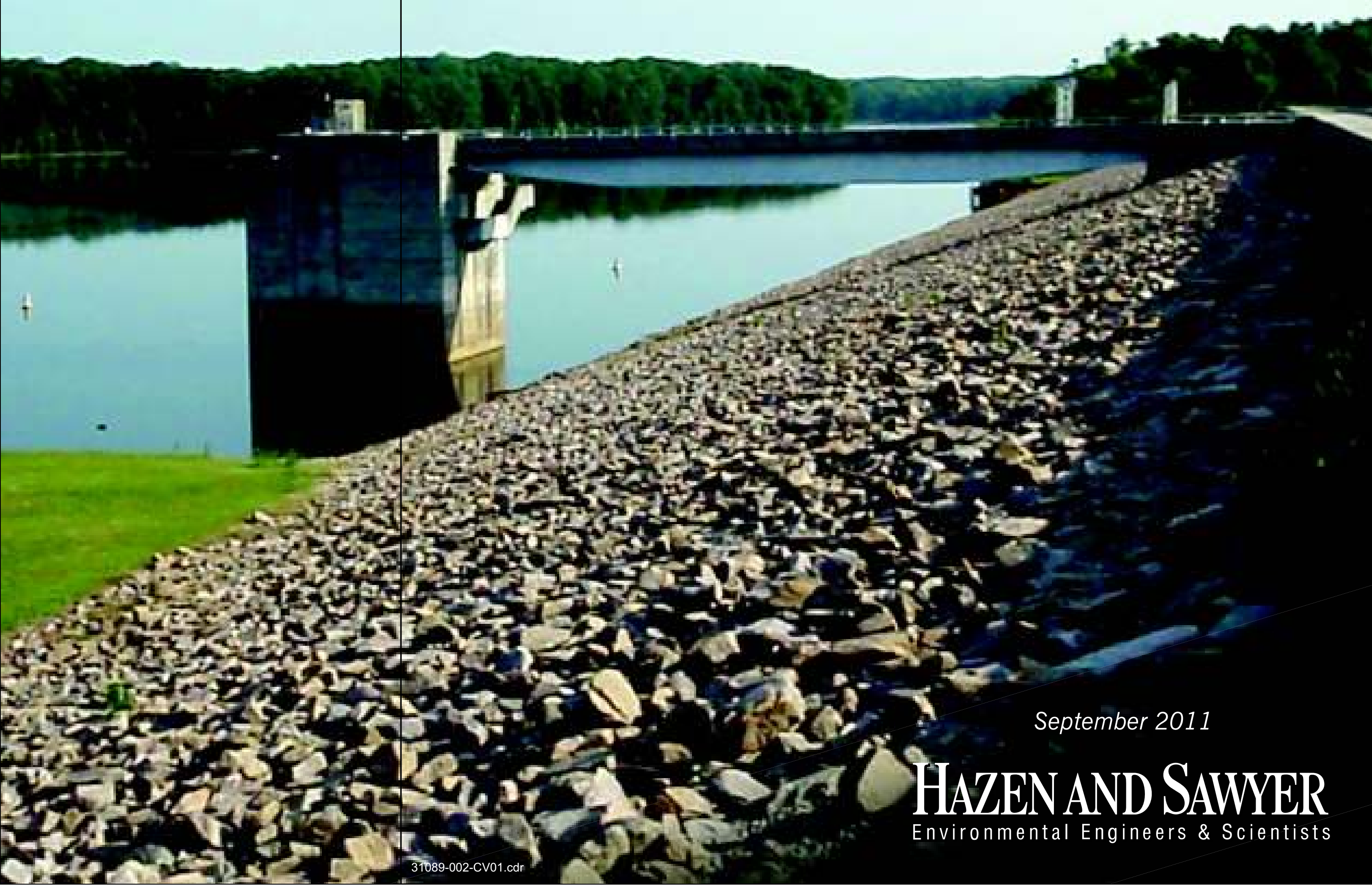
Falls Lake Dam Hydroelectric Project

Pre-Feasibility Study (FERC Project No. 13623)

City of Raleigh, North Carolina



September 2011

HAZEN AND SAWYER
Environmental Engineers & Scientists

31089-002-CV01.cdr

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EXECUTIVE SUMMARY

On November 19, 2010, the City of Raleigh ("City") was awarded a Preliminary Permit to conduct studies and prepare a license application for a hydroelectric project it referred to as the Falls Lake Dam Hydroelectric Project, Federal Energy Regulatory Commission ("FERC") Project No. P-13623 ("Project").

The pre-feasibility study has been prepared concurrently with the Pre-Application Document (PAD) to provide preliminary guidance to the applicant. The pre-feasibility study analyzes the variables that impact the economic viability of the development to determine if it should advance to a more detailed feasibility study. An opinion of probable construction costs ("OPCC") was developed from budgetary quotes from turbine vendors, R. S. Means Construction Cost Data ("Means") and internal information. Schematic plans were developed for two alternatives as well a preliminary energy analysis for each. Brubaker & Associates, Inc. ("BAI") prepared a preliminary 70-Year Progress Energy Avoided Cost Energy Price Forecast. A net present value ("NPV") analysis was completed using the cost, energy and energy price information.

Project Layouts

Two turbine vendors were contacted to solicit preliminary quotes for turbines and generators. **Table ES-1** summarizes the turbine equipment from the quotes received from the vendors and studied in this report.

Table ES-1: Hydropower Development Hydraulic and Electrical Capacities

Alternative Vendor	No. of Turbines and Runner Diameter Size	Rated Net Head (ft)	Hydroelectric Hydraulic Capacity (cfs)	Hydroelectric Generation Capacity (MW)
Alternative 1 Voith	2 turbines total 2 – 1085 mm (3.6 ft)	50.0	500	1.90
Alternative 2 CHEC	2 turbines total 2 – 1250 mm (4.1 ft)	40.0	600	1.70

Two hydroelectric alternatives are presented for this site. The first alternative proposes to extend the existing tunnel and convey water to a new powerhouse located on the southern stream bank downstream of the dam. The proposed hydroelectric plant will receive water from a branch off the proposed 17.5-foot diameter steel penstock extension of the existing tunnel. A new bypass gate structure will be constructed at the end of the new penstock which will discharge into the existing stilling basin. The hydroelectric plant will be served by a 10-foot diameter steel penstock which will be bifurcated to provide 7-foot diameter steel penstock branches to each of the two horizontal S-turbines.

The second alternative proposes to install vertical Kaplan turbines in the intake tower located at the upstream side of the dam. The existing intake structure has two conduit openings that discharge into the outlet tunnel. One turbine and generator will be contained within a steel framed module that will be attached to the upstream face of the intake tower. There will be two turbines and two generator units; one in front of each of the conduit openings. Under flood conditions the turbine/generator module will be raised above the conduit openings to allow flood waters to pass through unimpeded by the turbine.

Transmission Facilities

At this time it is not known whether the existing 13.2 kV line can accommodate the power from the hydroelectric facility. An interconnection study will need to done if the project goes forward. For this study it is assumed the existing 13.2 kV line will be adequate. For Alternative 1, a switchyard will be provided adjacent to the powerhouse with a step-up transformer for overhead transmission to the existing 13.2 kV transmission line located within 200 feet of the powerhouse. The existing line is owned by Progress Energy.

For Alternative 2, an electric control booth will be cantilevered off the top of the existing intake tower with electric conduits running along the existing bridge then underground for 700 feet to the existing 13.2 kV underground transmission line and a proposed step-up transformer.

Estimated Average Annual Generation and Carbon Offsets

Using the Operational Analysis Simulation of Integrated Systems ("OASIS") model developed by HydroLogics for the 82-year period of record (1929-2010), an energy analysis was performed based on the vendor-supplied turbine hydraulic capacities, turbine efficiency curves, estimates of headloss, and tailwater rating information. No changes are proposed to the operation of the dam. The United States Army Corps of Engineers ("USACE") will determine the discharge flows and the hydro operator will operate the turbines accordingly. **Table ES-2** presents the average annual energy estimates for the two alternatives and their associated OPCC.

Table ES-2: Falls Lake Dam Average Annual Generation and OPCC

Vendor/Layout	Alternatives – No. of Turbines and Runner Diameter Size	*Avg. Annual Generation over Period of Record (from OASIS Model)	OPCC Estimate ($2011)
Alternative 1 Voith	2 turbines total 2 – 1085 mm (3.6 ft)	7256 MWH/yr	$28,372,000
Alternative 2 CHEC	2 turbines total 2 – 1250 mm (4.1 ft)	4608 MWH/yr	$7,825,000
* All generation estimates assume a 5% downtime due to scheduled and unscheduled outages.			

Hydroelectric power is generated without any emission of carbon dioxide or other Greenhouse Gases (GHGs). The Carbon offset for Alternatives 1 and 2 are estimated to be 6060 metric tons and 3850 metric tons of CO_2 equivalents per year, respectively.

Net Present Value Analysis- Baseline Case

Using the average annual energy estimates, OPCC, and electricity price forecast, NPV analyses were conducted for each alternative for a baseline[1] case. The NPV baseline case parameters are listed in **Table ES-3**.

[1] The baseline case reflects the most likely scenario relative to energy pricing (reference), annual operation and maintenance costs ($20/MWH), and bond rate. Baseline case does not include any potential renewable power incentives that could be available.

Table ES-3: NPV Baseline Case Parameters

Variable	Baseline
Licensing Costs	Not included in NPV analysis
Engineering Design Costs	Alternative 1 Voith: $2,488,000, escalated at 4.5% annually Alternative 2 CHEC: $689,000 escalated at 4.5% annually
OPCC	Escalated annually at 4.5%
Energy (MWH)	Based on average annual generation produced by OASIS model for period 1929-2010, reflects 5% downtime Alternative 1 Voith: 7,256 MWH/yr Alternative 2 CHEC: 4,608 MWH/yr
Energy Price	Reference Price (nominal $/MWH) Progress Energy Avoided Energy Costs
Turbine Sizing	Alternative 1 Voith: 2 @ 55-250 cfs 55 cfs (22% of 250 cfs) Flow Range: 55-500 cfs Alternative 2 CHEC: 2 @ 85-300 cfs 85 cfs (29% of 300 cfs) Flow Range: 85-600 cfs
Annual O&M Costs	Alternative 1 Voith: $20/MWH $145,120 Alternative 2 CHEC: $20/MWH $92,160
Annual O&M Escalation Rate	3.0%
Capital Expenditures Escalation Rate	4.5%
Bond Issuance Rate	4.7%
Debit Service Retirement	30-yr

Table ES-4 lists by alternative, the NPV results for the baseline case.

Table ES-4: NPV Results for Baseline Case

Alternative Vendor	Alternatives –No. of Turbines and Runner Diameter Size	Baseline NPV, 50-yr with 50-yr Debt Retirement
Alternative 1 Voith	2 turbines total 2 – 1085 mm (3.6 ft)	-$16,815,618
Alternative 2 Andritz	2 turbines total 2 – 1250 mm (4.1 ft)	-$687,911

The large negative NPV for Alternative 1 shows that the downstream powerhouse alternative is not economically feasible over a 50-year term and 30-year debt retirement. For Alternative 2 – intake tower, the NPV is also negative, but the number is much more favorable than for Alternative 1.

Recommendations

Even though Alternative 2 is a marginal project, we recommend moving forward with a sensitivity analysis. This would provide a better sense of the impact of the input parameters on the NPV result. The parameters that could be changed include the price of power, bond rate, escalation rates and the annual O&M costs. The sensitivity analysis would show whether the project would have a positive NPV if the high energy price provided by BAI or a lower bond rate was used, as a couple of examples. Consideration of renewable power incentives could also be included in the NPV analysis.

Should the City elect to move forward with the project following the review of the sensitivity analysis results, the next step would be the preparation of a detailed feasibility study. By refining the energy price forecast and construction costs, a more accurate NPV can be determined.

The detailed feasibility study would include the following tasks:

- Obtain as-built drawings of the intake tower and dam and prepare an accurate base plan. If as-built drawings are not available, survey of the intake tower, bridge and transmission line area would be needed.
- Obtain more detailed turbine and generator information from CHEC for the intake tower development.
- Obtain quotes from additional turbine vendors.

- Develop a detailed energy price forecast based on projected avoided cost energy prices and renewable energy credit values applied to the estimated energy output associated with the project.
- Prepare an interconnection study to determine whether the existing transmission system can accommodate the power generated by the hydro facility.
- Meet with the USACE to discuss their engineering and operating concerns, and determine what structural analyses they require.
- Review the loading restrictions on the bridge and intake tower, and determine how that affects construction.
- Have a structural engineer visit the site to conduct a visual inspection of the intake tower and to obtain information to assist in developing conceptual design plans.
- Prepare a detailed headloss analysis.
- Have an electrical engineer prepare a one-line diagram, conceptual layout of the electric control booth, transmission line and transformer, and cost estimate.
- Further review of renewable power generation incentives.

Once the information from the above scope items is completed, the following work can commence for the detailed feasibility study.

- Refine energy analyses based on new turbine/generator information and detailed headloss calculations.
- Develop conceptual site drawings based on detailed topographic and planimetric features and new turbine/generator layouts. The design will take into consideration the maintenance of equipment and constructability.
- Analyze the recommended development to ensure it meets the USACE operation plan and dam safety requirements.
- Perform detailed quantity takeoffs based on new conceptual plans.
- Revise cost opinion based on new quantity takeoffs and market prices.
- Update the economic analysis based on the updated energy price projections, cost estimates and generated energy. A sensitivity analysis for the detailed feasibility study NPV runs can be done, if desired, and the results compared with the results of the baseline condition to see which input parameters have the greatest impact on the NPV. The parameters that can be changed include the price of power, bond rate, escalation rates and the annual O&M costs.

Prepare a report presenting the proposed project layouts, the turbine/generator equipment information and cost quotes, the energy price projections, the energy analyses, the interconnection study results, the construction cost estimates, and the economic analyses.

1 INTRODUCTION

1.1 Background

On November 19, 2010, the City of Raleigh ("City") was awarded a Preliminary Permit to conduct studies and prepare a license application for a hydroelectric project it referred to as the Falls Lake Dam Hydroelectric Project, Federal Energy Regulatory Commission ("FERC") Project No. P-13623 ("Project"). The Project is comprised of the development listed in **Table 1.1-1**.

Table 1.1-1: Falls Lake Dam Hydroelectric Project Development

Development	River	Drainage Area
Falls Lake Dam	Neuse River	771 mi^2

As an initial step in the process, the City authorized Hazen and Sawyer, P.C. to prepare a pre-feasibility assessment of the Project. Hazen and Sawyer, P.C. engaged Gomez and Sullivan Engineers, P.C. to provide specialty assistance in developing the pre-feasibility study. This pre-feasibility study analyzes the variables that impact the economic viability of the development to determine if it should advance to a more detailed feasibility study. The assessment is based on budgetary quotes from turbine vendors, cost estimating manuals, engineering expertise and experience, and information gleaned from other projects in which it has been involved.

The following tasks were conducted for this study. Greater detail on each task is described later in this report.

- The Wilmington District of the United States Corps of Engineers ("USACE") provided plans of the Falls Lake Dam and outlet release works.
- Schematic site base plans, and turbine plans and sections were developed for each alternative.
- Headloss calculations were estimated from the reservoir intake location to the turbine draft tube exit location for each alternative.
- Information was solicited from turbine vendors on equipment options and sizing, turbine efficiency curves, schematics/layouts, and preliminary pricing. The information provided was used to evaluate alternative designs and layouts, and the economic viability of hydroelectric generation for each alternative.
- An energy analysis was conducted using the outlet tunnel discharges and reservoir elevations from the Operational Analysis Simulation of Integrated Systems ("OASIS") model, turbine efficiency curves, turbine hydraulic capacities, estimated headlosses, and tailwater rating curve estimates.

- The turbine vendors were provided with the following:
    - Preliminary Permit Application Exhibit 4.2 Site Plan and Exhibit 4.3 Powerhouse Plan and Section.
    - The type of turbine, the approximate runner size, normal head range and rated discharge.

  Turbine vendors provided information on equipment sizing (cubic feet per second ("cfs")) and megawatts ("MW"), turbine efficiency curves, schematics/layouts and preliminary pricing. Voith and China Huadian Engineering Company ("CHEC") were contacted and provided quotes. As described later, the vendor quotes are budgetary, but are sufficient for this study.

- Brubaker & Associates, Inc. ("BAI") prepared a preliminary 70-Year Progress Energy Avoided Cost Energy Price Forecast.

- An opinion of probable construction costs ("OPCC") was developed from budgetary quotes from turbine vendors, R. S. Means Construction Cost Data ("Means") and internal information.

- Based on the energy analysis, layouts and OPCC, an economic analysis was conducted for each alternative.

Schedule

A schedule outlining the tasks following filing of the Final License Application and request for Section 401 Water Quality Certification is contained in **Appendix A.** The schedule represents a best estimate, as the timeline is governed by FERC's responsiveness and potential additional information requests that may be sought by the resource agencies, FERC, and non government organizations. Recognizing the schedule is not firm, it was estimated that a FERC license would be issued for the developments in January 2016. FERC typically requires construction to begin within two years of license issuance, with completion two years thereafter. For the NPV analysis, it was assumed the final design for the project would be done in the two year period prior to obtaining the license. The construction would start immediately after obtaining the license in January 2016 and would take 2 years to complete. The approximate 2-year design period is governed by the Intake Tower Alternative at the Falls Lake Dam Development. Work completed during the 2-year design period includes:

- 30%, 50%, 90% design drawings;
- City review of the 30%, 50%, and 90% design drawings;
- Permitting;
- Preparation of request for proposal for firm vendor turbine bids;
- Review of vendor bids, and engineers recommended selection;
- Preparation of request for bids for contractors;
- Review of contractor bids, and engineers recommended selection;
- City executes contracts with selected turbine vendor and selected contractor.

Reevaluation of Feasibility Assessment

Once the FERC issues a license for the Project, the City will know the final protection, mitigation, and enhancement ("PM&E") measures that will be required at each development. PM&E measures could impact capital costs, operational modifications, and O&M requirements. The City will need to evaluate when they wish to start the design process versus the risk of PM&E measures affecting the feasibility of the developments. If the City opts to start the design process after obtaining a license, the City should request a specific construction start date from FERC.

1.2 Development Criteria

The following criteria guided this pre-feasibility study:

- The energy and revenue analysis assumes that the Development is not peaked to maximize revenue during periods of the day when the price of power may be higher.

- The design layouts are based on maintaining full outlet release works flow capabilities without the turbines operating. In other words, the flow capacity of the release works without the turbines operating is preserved.

- The energy analysis utilizes flows that would otherwise spill up to the maximum capacity of the hydroelectric facility.

- The City reviewed and approved the inputs to the NPV analysis.

2 REGULATORY OVERVIEW AND WATER QUALITY GOALS

2.1 Turbine Vendors

Budgetary quotes for turbines, generators and associated equipment were solicited from the following vendors:

- Voith
- CHEC

Voith was contacted to provide a quote for Alternative 1- Downstream Powerhouse and CHEC for Alternative 2 – Intake Tower. Each vendor was provided an email requesting that budgetary quotes be provided for the following equipment: turbines, generators, gearbox, controls, hydraulic power unit ("HPU") and switchgear. The email explained that, based on our preliminary analysis, horizontal Kaplan S- turbines for Alternative 1 and vertical Kaplan turbines for Alternative 2 were the preferred options based on the head, flow range and layout. The Preliminary Permit Application Exhibit 4.2 Site Plan and Exhibit 4.3 Powerhouse Plan and Section were provided, as well as, the approximate runner size, normal head range and rated discharge.

The budgetary quotes received are attached in **Appendix B**. Details on each vendor budgetary quote are provided within the discussion below.

2.2 Falls Lake Dam Hydroelectric Development

Layouts

Two hydroelectric alternatives are presented for this site. The first alternative proposes to extend the existing tunnel and convey water to a new powerhouse located on the southern stream bank downstream of the dam. The second alternative proposes to install turbines in the intake tower located at the upstream side of the dam. The following figures include layout drawings for the alternatives evaluated:

- **Figure 2.2-1**. Falls Lake Dam General Project Location Map
- **Figure 2.2-2**. Falls Lake Dam Facilities Location Plan
- **Figure 2.2-3**: Falls Lake Dam Development: Alternative 1: Downstream Powerhouse and Alternative 2: Intake Tower - Site Plan
- **Figure 2.2-4**: Falls Lake Dam Development: Alternative 1: Downstream Powerhouse - Plan and Section
- **Figure 2.2-5**: Falls Lake Dam Development: Alternative 2: Intake Tower – Plan and Section

Figure 2.2-1 presents the project location within the State. **Figure 2.2-2** shows the Falls Lake Dam and its associated facilities. **Figure 2.2-3** presents an overview of the area around the dam and the locations of the Downstream Powerhouse and Intake Tower Alternatives. **Figure 2.2-4** presents the powerhouse plan and section for the Downstream Powerhouse Alternative. **Figure 2.2-5** presents the roof plan and section for the Intake Tower Alternative.

Alternative 1

For Alternative 1, the proposed hydroelectric plant at Falls Lake will receive water from a branch off the proposed 17.5-foot diameter steel penstock extension of the existing tunnel. A new bypass gate structure will be constructed at the end of the new penstock which will discharge into the existing stilling basin (see **Figure 2.2-3**).

The hydroelectric plant will be served by a 10-foot diameter steel penstock which will be bifurcated to provide 7-foot diameter steel penstock branches to each of the two turbines. Each turbine will be provided with a butterfly valve designated to close for emergency shutdown of the turbines.

Each of the two horizontal Kaplan S-turbines will have a rated flow of 250 cfs at 50 feet of head and will operate at 514 rpm. Each unit will produce 0.95 MW for a total station capacity of 1.9 MW. The 2 turbine-generator units will be contained within a reinforced concrete powerhouse of the approximate dimensions shown on the accompanying drawing (see **Figure 2.2-4**). A tailrace will be excavated adjacent to the existing stilling basin to accept discharge from the units.

A temporary siphon will be constructed over the spillway to provide conservation and directed flows during construction. Use of a temporary siphon will require that reservoir elevations be managed between the spillway crest and 20 feet below the spillway crest. If the reservoir elevation drops below 20 feet of the spillway crest, the siphons will not operate and downstream flows will cease.

A major challenge with this alternative is the need to divert flows from the tunnel downstream of the outlet tower during construction. The options for achieving this diversion are limited, and the available options could reduce the capacity to pass flood releases from the Falls Lake facility during construction, and therefore bring into question as to whether the USACE, other facility stakeholders and potentially affected parties would accept this alternative. Consequently, Alternative 2 is anticipated to be less viable due to constructability concerns, but is developed as an alternative for this pre-feasibility study.

A switchyard will be provided adjacent to the powerhouse (see **Figure 2.2-3**). The voltage will be 4160 V from the generators and will be stepped up via a transformer to 13.2 kV for overhead transmission to an existing 13.2 kV transmission line located within 200 feet of the powerhouse. The existing line is owned by Progress Energy.

Alternative 2

For Alternative 2, vertical Kaplan turbines will be installed on the intake tower, which is located at the upstream face of the dam. The existing intake structure has two conduit openings that discharge into the outlet tunnel. One turbine and generator will be contained within a steel framed module that will be attached to the upstream face of the intake tower. There will be two turbines and two generator units; one in front of each of the conduit openings. Under flood conditions the turbine/generator module will be raised above the conduit openings to allow flood waters to pass through unimpeded. It should be noted this is a non-typical hydroelectric installation. One component that will require special design is the shaft between the generator and the turbine which is over 40 feet long. There is one other similar facility that is currently being constructed at Jordan Lake in North Carolina.

Figure 2.2-5 presents the roof plan and a section through the proposed modules and existing intake tower. The module tower is approximately 78 feet tall and 9 feet by 9 feet square. The turbine is located near the bottom of the module and the generator nearer the top at elevation 260, above the normal pool elevation of 251.5. A flume is created by covering the steel frame with steel panels. The water enters the flume through the upper trashrack then falls vertically trough the turbine and exits via the draft tube into the existing tunnel. There is a second trashrack at the bottom of the module that protects the turbines from debris. A section of concrete at the top of the existing tunnel entrance will need to be removed to allow room for the module to pass through it. There are two fixed platforms that are attached to the intake tower. These allow access to the equipment for maintenance. The turbine can be raised to the elevation of the lower platform for maintenance.

Each of the two turbines will have a rated flow of 300 cfs at 40 feet of head and will operate at 450 rpm. Each unit will produce 0.85 MW for a total station capacity of 1.7 MW. For release rates beyond 600 cfs, two proposed spill gates located near the two turbines will be opened and the turbines can continue operating up to a total discharge of 2100 cfs. For flows greater than 2100 cfs, the modules will be raised slightly to allow water to pass under, or the water quality gates will be opened. When the release rate exceeds 4000 cfs (less than 2% of the time according to both OASIS and gage records), the modules will be raised completely, allowing flow to enter the tunnels unimpeded.

The USACE will determine the discharge flows and the hydro operator will operate the turbines and spill gates accordingly. Operation of the water quality, service and emergency gates will be by the USACE. The hydro operator will raise and lower the modules as required for flow changes.

An electric control booth will be cantilevered off the existing intake tower roof and will provide switchgear and breakers (see **Figure 2.2-5**). The voltage will be 4160 V from the generators and will be transmitted underground for 700 feet to the existing 13.2 kV underground transmission line where it will be stepped up via a transformer to 13.2 kV.

Table 2.2-1 summarizes the information on the number of turbines, type, rated net head, flow capacities, generation capacity, runner diameter, and rated speed provided by each vendor.

Table 2.2-1: Falls Lake Dam - Equipment Statistics

Statistic	Alternative 1 Vendor: Voith	Alternative 2 Vendor: CHEC
No. of Turbines/ Runner Diameter	2 @ 1085 mm (3.6ft)	2 @ 1250 mm (4.1 ft)
Turbine Type	Horizontal Kaplan S-turbine	Vertical Kaplan
Rated Net Head	50.0 ft (15.24 m)	40.0 ft (12.20 m)
Min and Max Turbine Flow Capacity	2 @ 55-250 cfs Total: 500 cfs Min Operating Flow= 55 cfs (22% of 250cfs)	2 @ 85-300 cfs Total: 600 cfs Min Operating Flow= 85 cfs (29% of 300 cfs)
Max Turbine Generation Output	2 @ 0.95 MW Total: 1.90 MW	2 @ 0.85 MW Total: 1.70 MW
Rated Speed	2 @ 514 rpm	2 @ 450 rpm

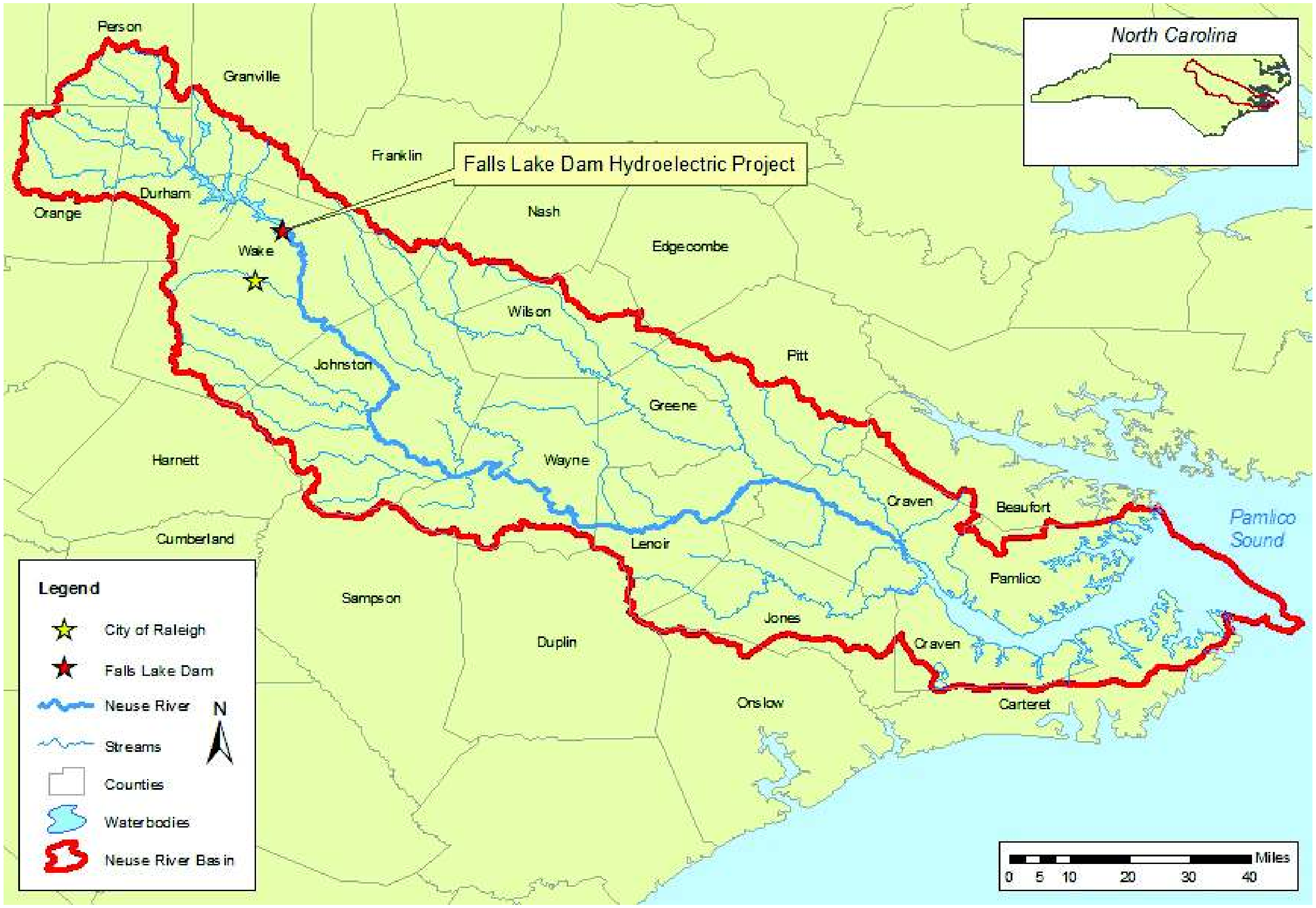
2.3 Turbine Quotes

Vendors provided only budgetary quotes at this time. They will not provide firm pricing until formal bids are requested; however, these quotes are sufficient for this feasibility analysis. **Table 2.3-1** shows the pricing information provided by the vendors. The quotes did not include prices for all of the electrical equipment and installation costs. Both of the quotes included the costs for turbines and generators with exciters. The pricing was adjusted to ensure that all quotes were comparable. Adjustments included additional costs for installation, control panels, programmable logic controllers ("PLC"), HPUs, switchgear, station service equipment, transportation to the site, import duties and the vendor's advisor during construction and commissioning. In the OPCC, the turbine/generator cost and the accessory electrical equipment costs are entered as separate items. The accessory electrical equipment costs include the HPU, control panels, PLC, switchgear and station service equipment. The vendor's advisory service during construction is to witness that the equipment has been installed according to warranty and to provide assistance during the start up of the equipment.

Table 2.3-1: Turbines, Generators (T/G) and Accessory (Acc.) Electrical Equipment

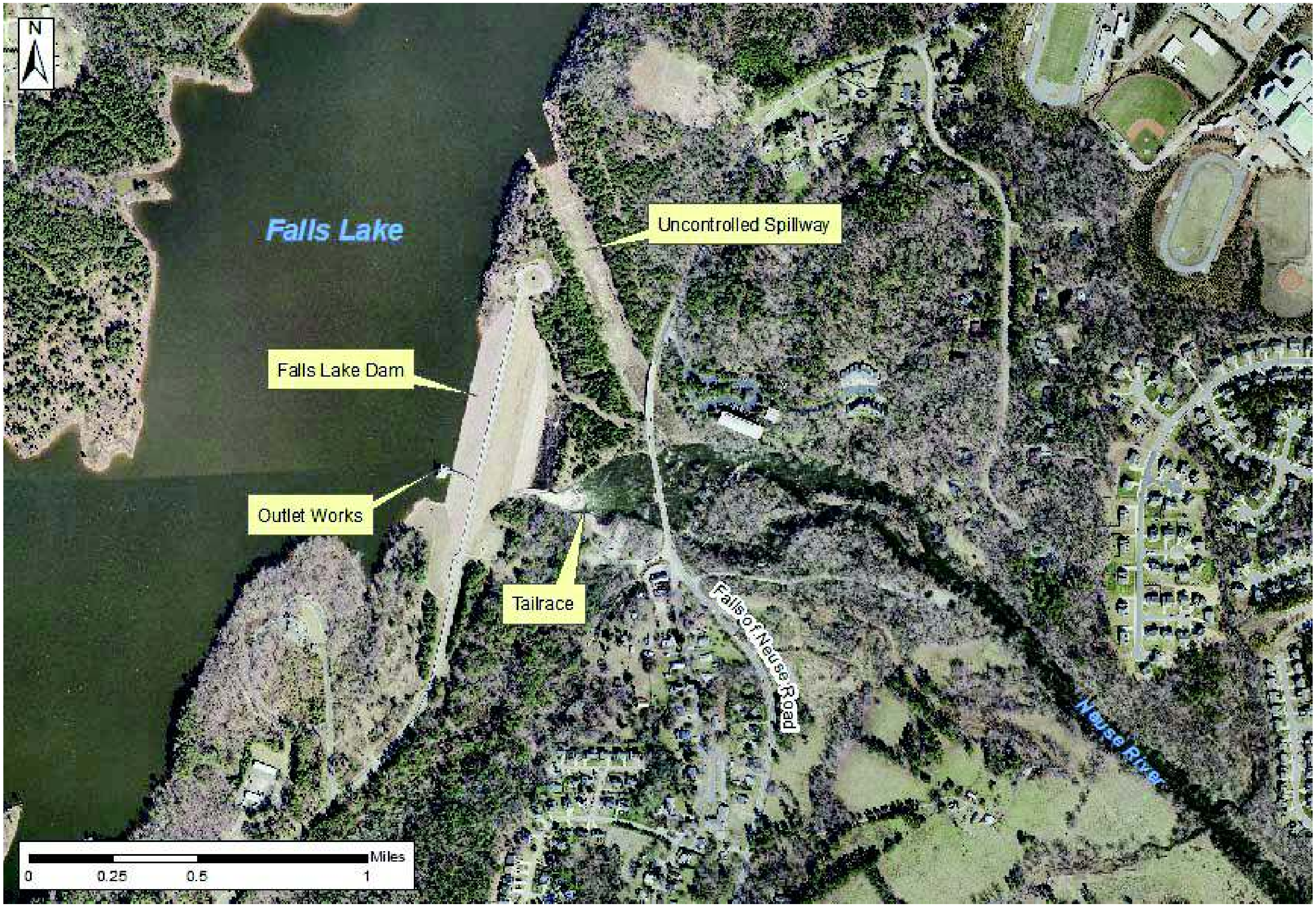
Vendor	Falls Lake Dam
Alternative 1 - Voith Budgetary Estimate:	$4,630,000
Total with Adjustments:	$5,780,000
Acc. Electric Equip.	$1,120,000
T/G Cost (Total w/ Adj.- Acc. Electric Equip.)	$4,660,000
Alternative 2 - CHEC Budgetary Estimate:	$1,000,000
Total with Adjustments:	$2,660,000
Acc. Electric Equip.	$430,000
T/G Cost (Total w/ Adj.- Acc. Electric Equip.)	$2,230,000

Figure 2.2-1: Falls Lake Dam General Project Location Map



Data Source: North Carolina State – USGS Seamless, Counties – USGS Seamless, Cities – USGS Seamless, Dam – USGS Seamless, Streams - Major Hydrography: NC Center for Geographic Information and Analysis (nconemap.com), Watershed – 8-digit HUs

Figure 2.2-2: Falls Lake Dam Facilities Location Plan



Data Source: Imagery – Local Orthophotography – Wake County 2005 (nconemap.com)

**Figure 2.2-3: Alternative 1:Downstream Powerhouse &
Alternative 2:Intake Tower–Site Plan**

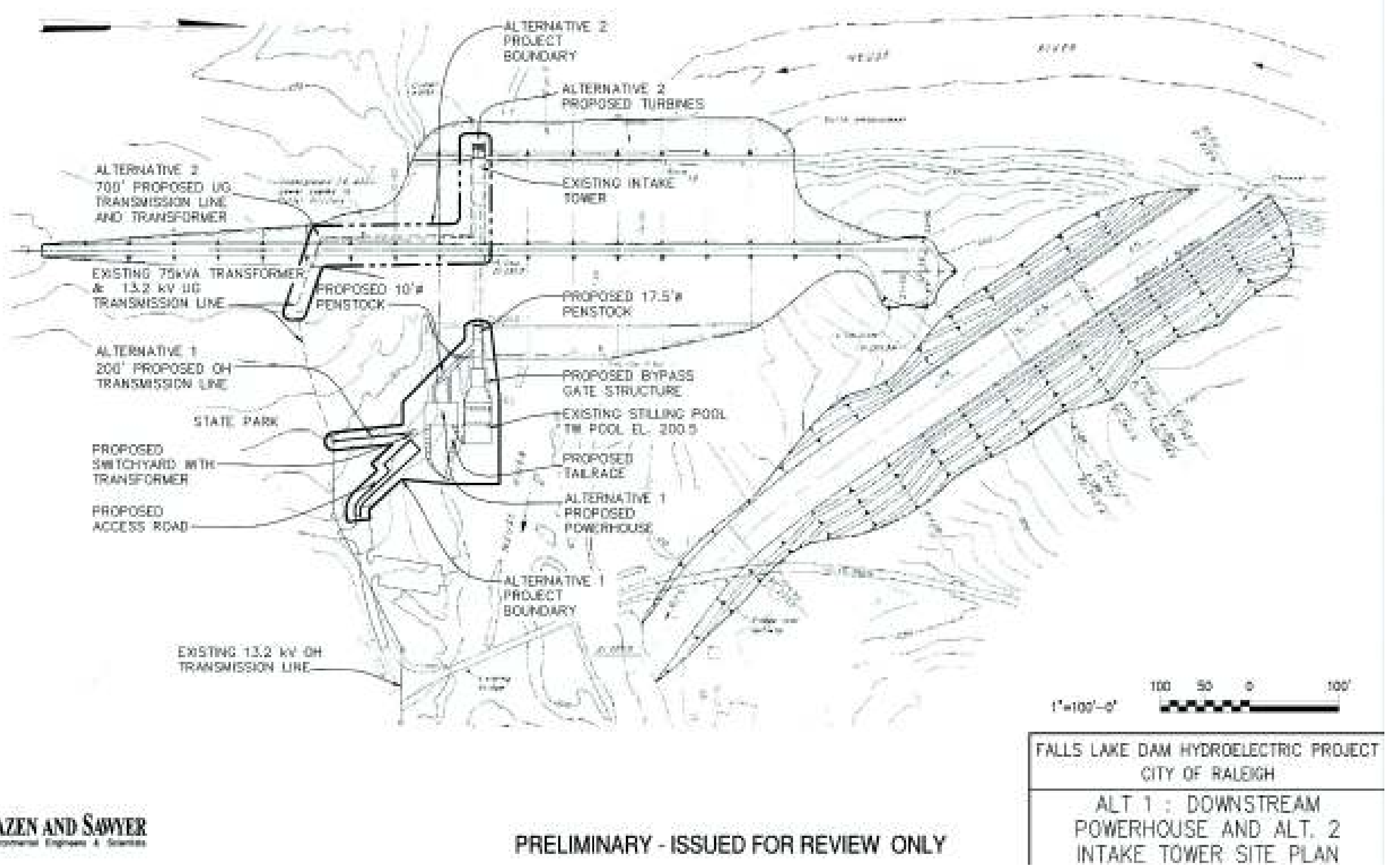


Figure 2.2-4: Alternative 1: Downstream Powerhouse – Plan and Section

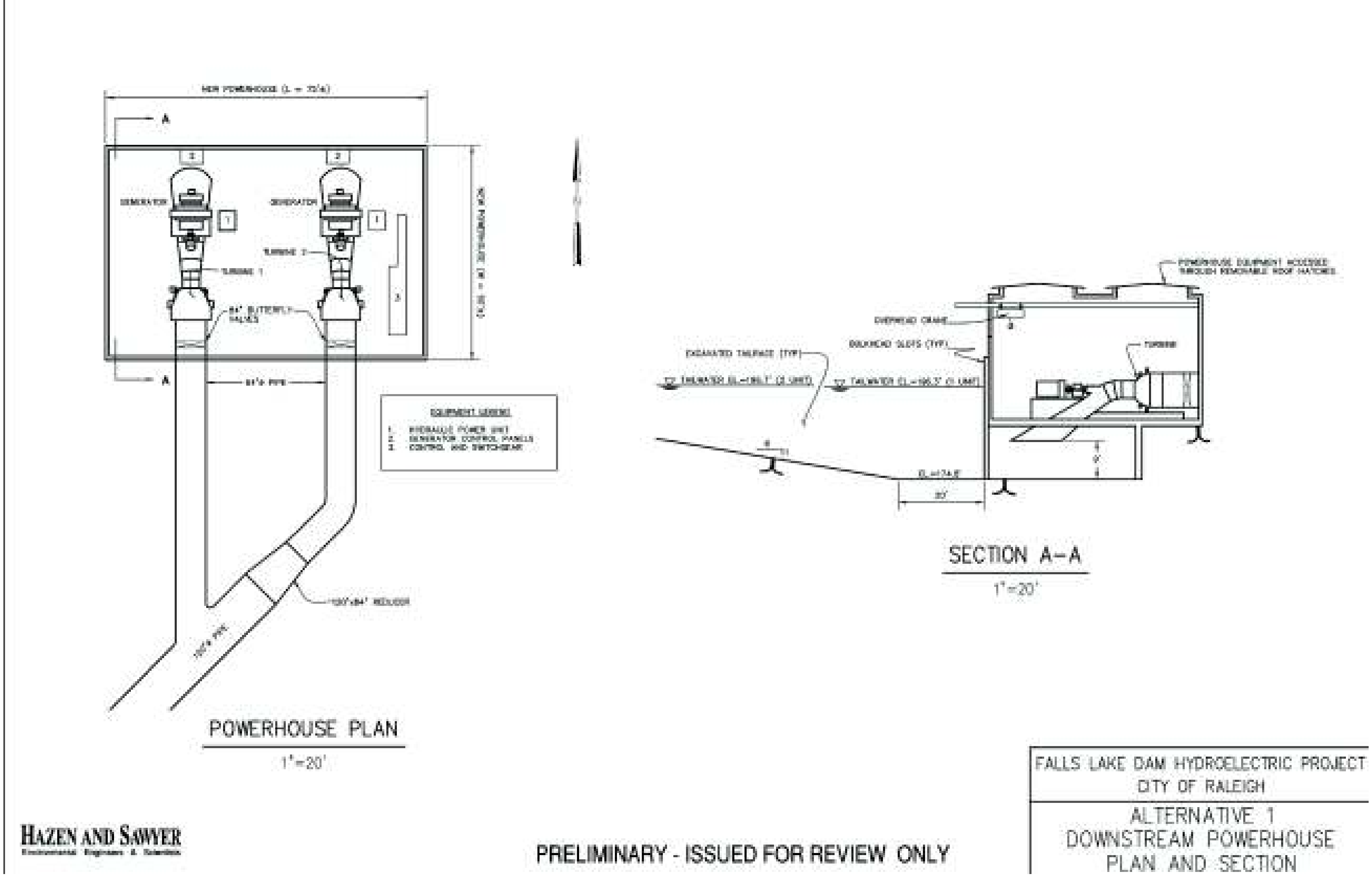
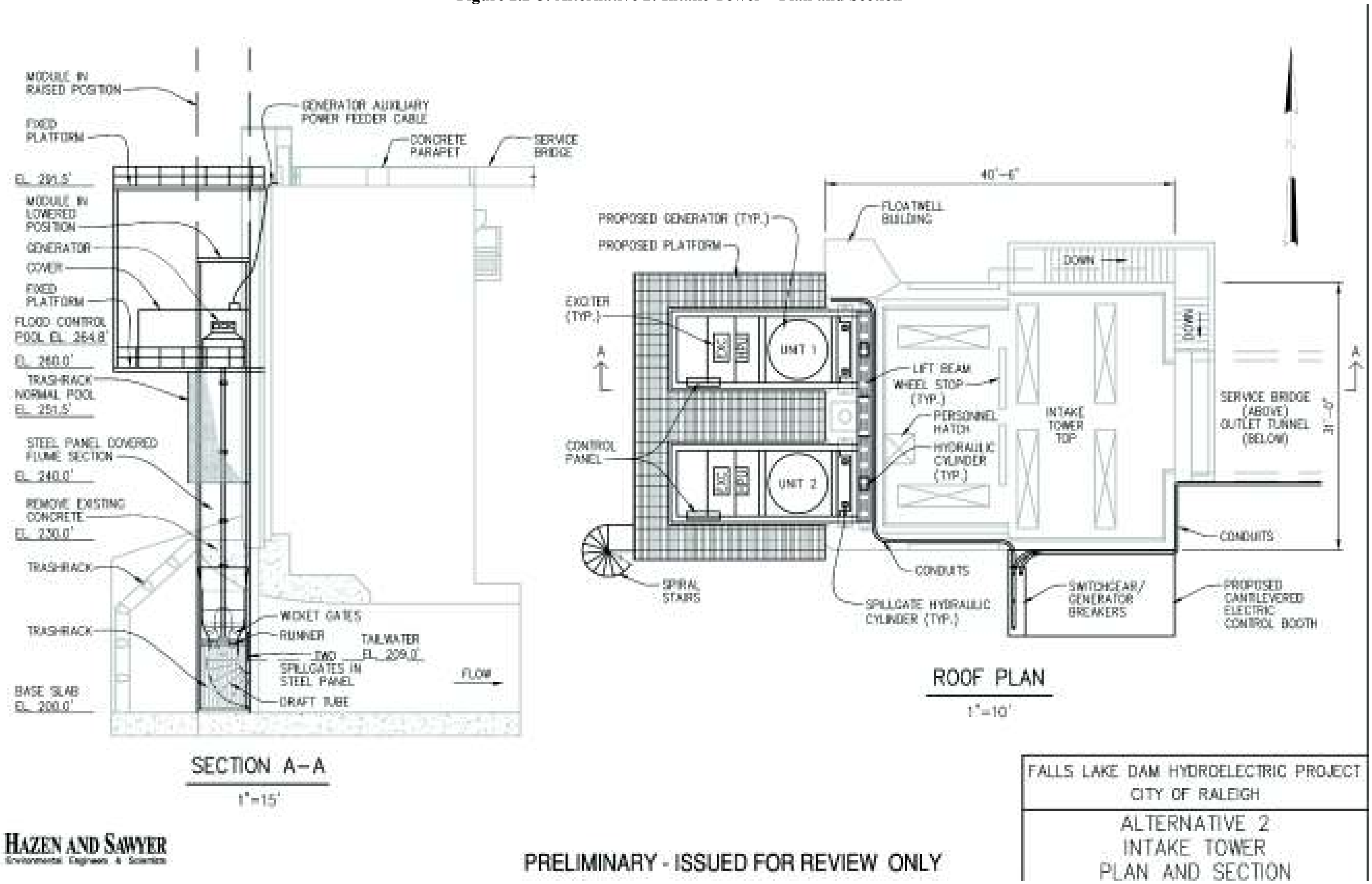


Figure 2.2-5: Alternative 2: Intake Tower – Plan and Section



3 CURRENT OPERATIONS

The current plan of operation includes maintaining a target elevation, also known as normal pool elevation, of 251.5 feet NGVD29 (The National Geodetic Vertical Datum of 1929) year round. Flood control storage space is reserved between elevations 251.5 and 264.8 feet NGVD29 with surcharge storage provided above the crest of the free-over-flow spillway (elevation 264.8 feet, NGVD). Conservation storage between elevations 236.5 and 251.5 feet NGVD29 is reserved for water supply as well as low flow and water quality control.

Water Quality Pool releases are made from the Outlet Works at the Falls Lake Dam (See **Figure 2.2-2**). The rate of release from the Water Quality Pool is dictated by several factors. Releases from the Water Quality Pool are calibrated to develop a minimum target flow at the Clayton stream gage which is 33 river miles downstream of the Falls Lake Dam. The flow target at the Clayton gage is 184 cfs during the period of November 1st through March 31st and 254 cfs from April 1st through October 31st. However, immediately below the dam there is a second minimum flow requirement. During the November 1st to March 31st period, the minimum flow requirement is provided by opening both piggyback gates which release approximately 60 cfs (50 cfs to 62 cfs depending on the hydraulic head on the gates). From April 1st through October 31st the flow requirement at the foot of the dam is 100 cfs. This second minimum flow requirement is enforced when less flow or even no flow would otherwise be needed in order to attain the minimum flow target at the Clayton gage. This ensures that the portion of the river immediately downstream of the dam always has water flowing in it. Discharges from the multilevel water quality gates are maintained from May 1 through November 14 during non-flood release periods to ensure that the highest quality water is released downstream. When the lake elevation is above the normal pool the USACE may release flow in excess of the minimum flow requirement through the Outlet Works as dictated by its flood mitigation strategy.

The proposed Project is an instantaneous run-of-the-river facility utilizing the existing dam and reservoir. At this time, there are no proposed changes in operation compared to the present mode of operation. The expectation is to generate power from the releases already being made through the Outlet Works from the Water Quality Pool and Flood Pool in accordance with USACE policy.

4 ENERGY MODELING

4.1 Overview of OASIS Model

The North Carolina Division of Water Resources ("DWR") commissioned the development of a hydrologic model of the Neuse River Basin. The model incorporates 82 years of daily recorded hydrologic history in the basin from 1929 through 2010 and includes the approximately 20 significant reservoirs in the basin, including Falls Lake. The model was created by HydroLogics using OASIS, a generalized computer program for modeling the operation of water resources systems, and was accepted by DWR in early 2010. It is the official model for water resource management use by DWR, North Carolina Department of the Environment and Natural Resources ("NCDENR").

OASIS models represent a river basin system using nodes (demands, inflow, reservoirs, etc.) and arcs (aqueducts, streams, etc.), and use linear programming optimization to simulate water routing decisions (e.g., reservoir releases or diversions) in the system using a daily time step, subject to both human operating rules and physical constraints. The OASIS model of the Neuse River Basin simulates the water supply demands, conservation releases, water level drawdowns, release mitigation needs, and other requirements applicable for each reservoir in the basin. Output from the OASIS model includes daily reservoir elevations, total discharge, hydropower discharge, conservation releases, water supply withdrawals, and spillage. The model simulates daily operations throughout the entire basin, including the current (2008) protocol provided by the USACE for making releases from Falls Lake Dam. Thus, the entire 82-year period of record for Falls Lake is modeled based on current lake operating protocol. For the purposes of this feasibility analysis, the model was used to develop a time-series of simulated releases from Falls Lake Dam over the period of available hydrologic history using the official USACE protocol for managing the Falls Lake Project. The time-series of daily release volumes was then used to evaluate the feasibility of a hydropower facility on Falls Lake, as described in other sections of this report. The general premise is that the previous 82 years of inflow will be representative of future inflows.[2]

4.2 Hydropower Inputs

The OASIS model simulates the reservoir operations. Its outputs include discharges below each dam, reservoir elevations, and water withdrawals. These variables remained fixed for the evaluation of each hydropower alternative. To simulate hydropower generation, we developed a post-processor whereby the OASIS model outputs of discharges below each dam and reservoir elevation were used in conjunction with turbine efficiency curves,

[2] There is no guarantee that the flows over the previous 82 years, from a hydrologic perspective, will occur in the future. Changes to land use in the watershed and climate change could result in changing the hydrologic budget. It is not typical to evaluate these types of factors in this analysis.

tailwater rating curves and estimated headlosses, to estimate daily and annual generation for the alternatives described in Section 2.

The post-processor computed the daily generation using the following formula:

$P = (H_{net} \times Q \times E)/11.8$, where:

P: Daily Power Generation (kW)
H_{net}: Net Head, or Reservoir Elevation (ft) - Tailwater Elevation (ft) - Headloss (ft)
Q: Turbine Discharge (cfs)
E: Composite Turbine/Generator Efficiency (%)
11.8: conversion factor

4.2.1 Reservoir Elevations

The reservoir elevation data was obtained from the OASIS model output, which is based on the National Geodetic Vertical Datum of 1929 ("NGVD29"). Figure **4.2.1-1** shows the annual reservoir elevation duration curves for Falls Lake Dam Reservoir based on the OASIS Neuse River Basin modeling. The spillway crest elevation is also shown on the figure. The reservoir elevation duration curves were developed with the 2010 water supply demand of 52 MGD (44 MGD from Falls Lake and 8 MGD from the City's other reservoirs) and at a future projected demand of 77 MGD. The future demand of 77 MGD is based on maximal use of existing water supply sources. Recent demand projections indicate this level of water demand could be reached in the 2025 to 2030 time horizon. The maximum, median, and minimum reservoir elevations are summarized in **Table 4.2.1-1**. This table also summarizes the percentage of time the reservoir elevation would be expected to exceed the spillway crest elevation (*i.e.*, resulting in spill) based on current USACE operating policies.

Table 4.2.1-1: Reservoir Elevation Statistics for Falls Lake Dam Reservoir (Datum: ft, NGVD1929)

Statistic	Falls Lake Dam
% of Time Reservoir Elevation Exceeds Spillway Crest Elevation on an Average Annual Basis	Less than 0.10%
Spillway Crest Elevation	264.8
Maximum Reservoir Elevation	267.0
Median Reservoir Elevation	251.0
Minimum Reservoir Elevation	241.6
Source: OASIS Modeling Results, Period of Record, 1929-2010	

4.2.2 Tailwater Elevations

The tailwater elevation represents the approximate water surface elevation ("WSE") immediately below the turbine(s) and varies based on flow.

For Alternative 1, the discharge rating curve from the USGS gage number 02087183, located just downstream of the Falls Lake Dam, was used to determine the tailwater elevation at the downstream side of the powerhouse.

For Alternative 2, a constant tailwater elevation of 209.0 was used. This elevation is 2 feet above the top of the draft tube and will be controlled by the downstream service gates.

4.2.3 Headlosses

Headlosses occur from the reservoir intake to the turbine discharge location. Headlosses are attributable to trashracks, entrances, bends, tees, junctions, gates, valves, penstock friction, contraction/expansion, and draft tube exit losses. Headlosses, expressed in feet, are computed by multiplying a headloss coefficient (C, unitless) times the velocity head ($v^2/2g$).

$H_L = C * v^2/2g$, where

H_L = headloss (in feet)
C = headloss coefficient (unitless). This headloss coefficient varies depending on the headloss element (bend, valve, etc.)
v = velocity (ft/sec)
g = acceleration due to gravity (32.2 ft/sec^2)

Considerable literature is available on headloss coefficients.[3] The literature sources provide a range for the headloss coefficients and thus professional judgment is used to select an appropriate C value. For this pre-feasibility level of study, a total estimated headloss was selected for each alternative based on engineering experience. For Alternative 1, the headloss was estimated to be 2 feet. For Alternative 2, the headloss was estimated to be 1.5 feet. For the next level of feasibility study, detailed headloss calculations will be done for each specific loss.

Table 4.2.3-1 shows the estimated headlosses for each alternative.

[3] Most headloss coefficients are determined under controlled laboratory conditions.

Table 4.2.3-1: Falls Lake Dam – Estimated Headloss

Vendor, No. of Turbines and Runner Diameter Size	Hydroelectric Hydraulic Capacity	Maximum Headloss	Design Head	Headloss Relative to Design Head
Alternative 1 Voith 2 – 1085 mm (3.6 ft)	500 cfs	2.0 ft	50.0 ft	4%
Alternative 2 CHEC 2 – 1250 mm (4.1 ft)	600 cfs	1.5 ft	40.0 ft	4%

4.2.4 Turbine-Generator Efficiencies

Vendors' supplied turbine efficiency curves for each development are included in **Appendix B**. The turbine efficiency curves used in the energy assessment are based on the maximum design head. They are of a typical shape, with lower efficiencies occurring at lower flows, increasing to peak efficiency at what is commonly called "best gate" and then decreasing thereafter to the maximum hydraulic capacity of the turbine.

The efficiency of the generators was not provided by the turbine vendors. The vendor turbine efficiency curves were multiplied by a constant generator efficiency of 95%[4] to yield a turbine-generator efficiency curve for each turbine.

During the design phase of this project, vendors will be asked to provide more detailed turbine efficiency curves, including curves for a range of head conditions. As necessary, the energy analysis can be refined using these more detailed curves.

4.2.5 Development Hydraulic Capacities

Figure 4.2.5-1 shows the average annual discharge duration curves representing releases from Falls Lake Dam based on the OASIS modeling with the current water supply demand of 52 MGD and the future demand of 77 MGD. **Table 4.2.5-1** presents the minimum flow in which one turbine can operate, as well as the maximum hydroelectric capacity for each alternative. Also shown in the table is the approximate percentage of time (on average annual basis) the minimum and maximum hydroelectric capacities are equaled or exceeded.

[4] The selection of 95% generator efficiency is based on professional judgment.

Table 4.2.5-1: Falls Lake Dam Turbine Hydraulic Capacities

Vendor, No. of Turbines and Runner Diameter Size	Minimum Hydroelectric Flow to Spin Smallest Turbine	Percent of Time Minimum Hydroelectric Capacity is Exceeded on Average Annual Basis	Maximum Hydroelectric Flow	Percent of Time Maximum Hydroelectric Capacity is Exceeded on Average Annual Basis
Alternative 1 Voith 2– 1085 mm (3.6 ft)	55 cfs	99.9%	500 cfs	26%
Alternative 2 CHEC 2 –1250 mm (4.1 ft)	85cfs	85%	600 cfs	23%

4.2.6 Development of Generation Estimates

The average annual generation was computed over the period 1929-2010. Each day's generation was computed using the post-processor based on the following:

- The daily reservoir elevation and release works discharge was produced by the OASIS model with the future projected water supply demand of 77 MGD.
- The daily headloss, tailwater elevation, and turbine-generator efficiency for the release works discharge was determined from the respective rating curves or fixed entry.
- The daily net head was computed by subtracting the headloss and tailwater elevation from the reservoir elevation.
- The daily generation was computed using the power equation with inputs of turbine-generator efficiency, net head, and release works discharge. The daily generation was multiplied by 24 hours/day to yield kilowatt hours ("KWH").
- The daily generation was then summed annually and the average generation was computed for the period of record (in MWH), which was used as input to the NPV analysis.

Table 4.2.6-1 shows the average annual generation for each development and alternative.

Table 4.2.6-1: Falls Lake Dam Average Annual Generation

Alternative / Vendor	No. of Turbines and Runner Diameter Size	Minimum and Maximum Hydroelectric Flow	Rated Net Head	Hydroelectric Generation Capacity MW	*Avg. Annual Generation MWH/yr
Alternative 1 Voith	2 – 1085 mm (3.6 ft)	55- 500 cfs	50.0 ft	1.90	7256
Alternative 2 CHEC	2 – 1250 mm (4.1 ft)	85 -600 cfs	40.0 ft	1.70	4608
* Assumes 5% downtime due to scheduled and unscheduled outages.					

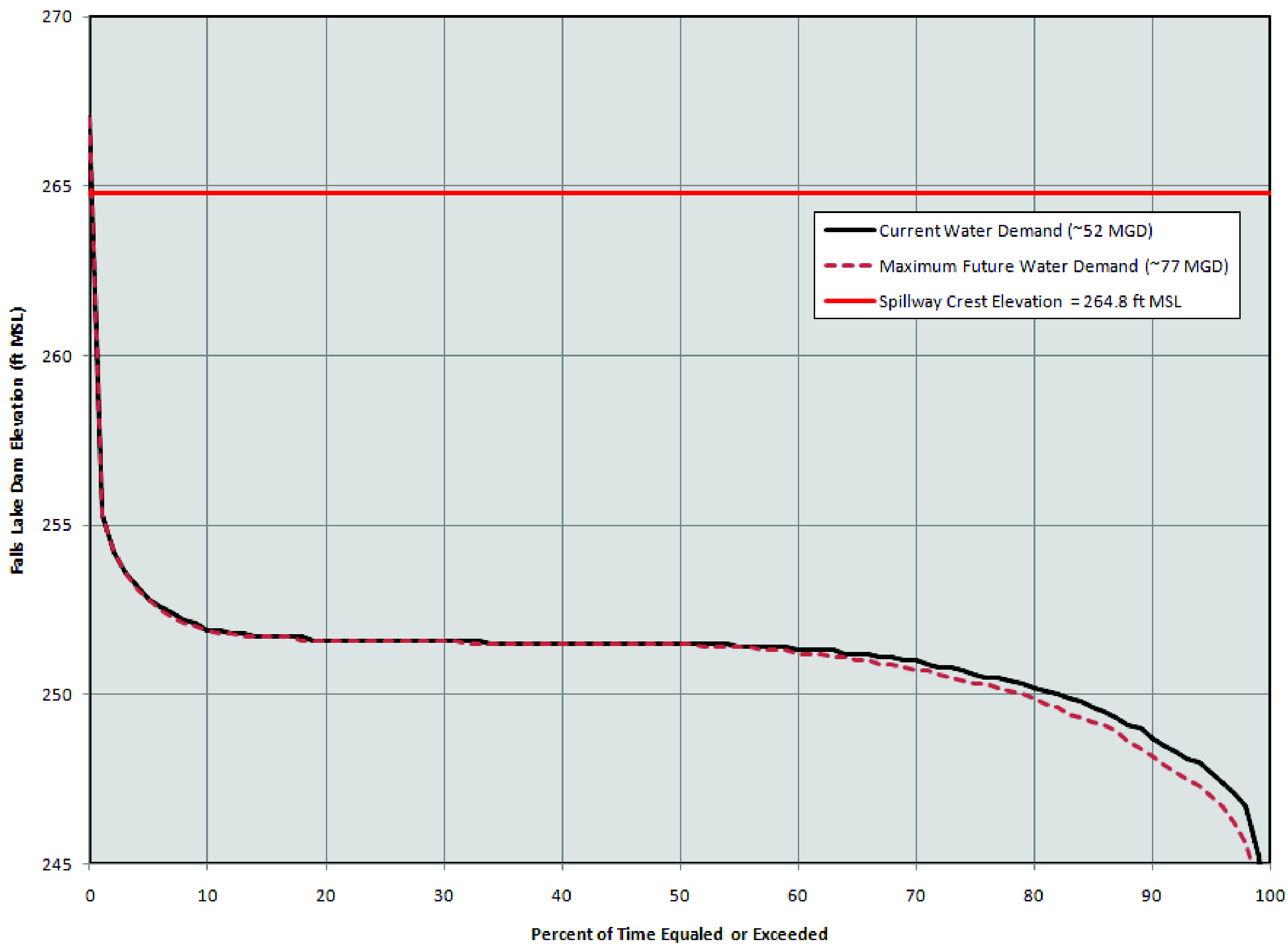


Figure 4.2.1-1: Falls Lake Dam Annual Reservoir Elevation Duration Curve, OASIS, Period of Record 1929-2010

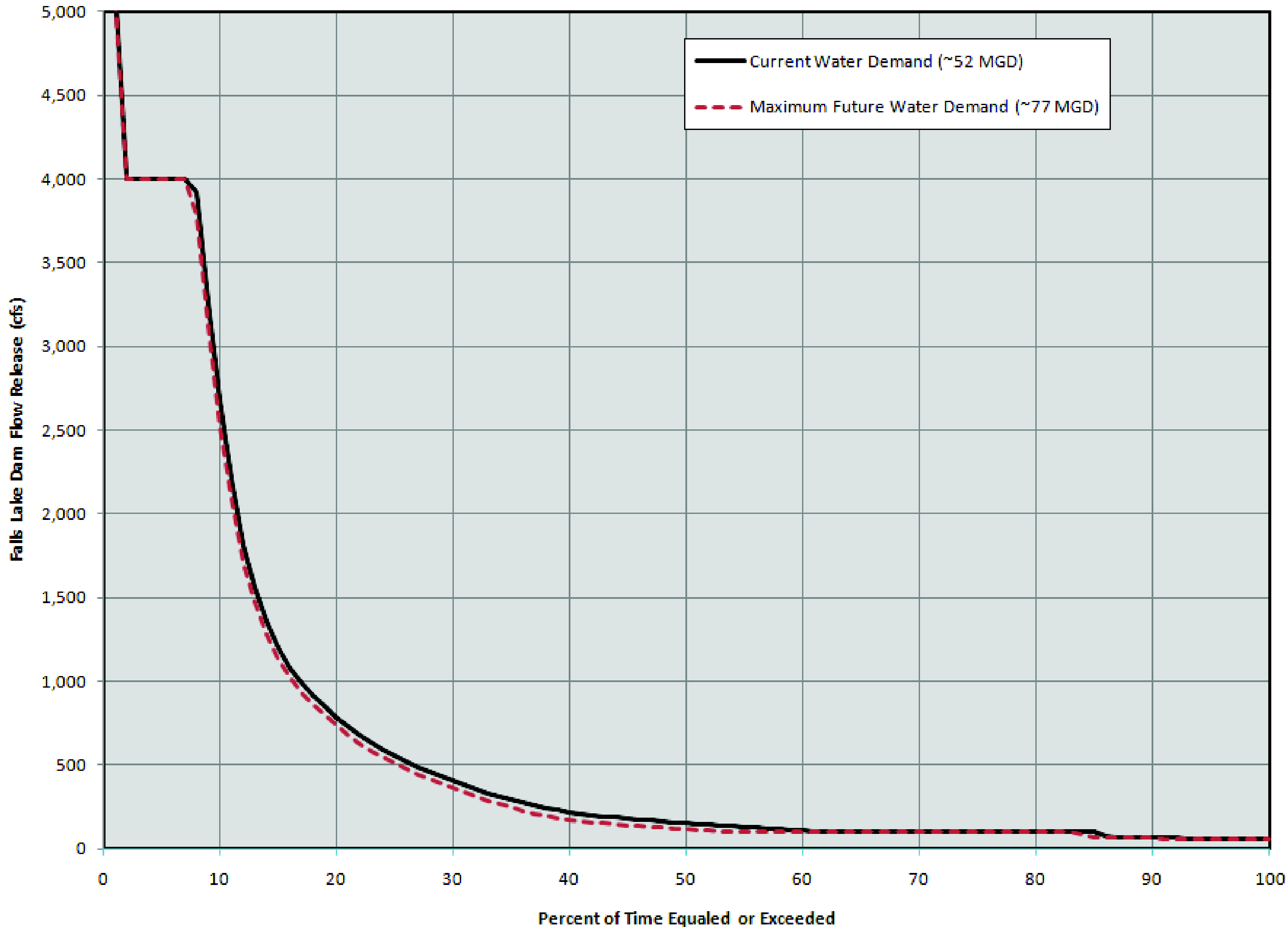


Figure 4.2.5-1: Falls Lake Dam, Annual Flow Duration Curve, OASIS, Period of Record 1929-2010

4.2.7 Carbon Offsets

Hydropower generation relies on the force of falling water to spin a turbine which is connected to a generator and does not require the combustion of any fuel. As such, the process of hydroelectric generation does not emit carbon dioxide or any other greenhouse gas (GHG). Therefore the power that would be produced by this project can be considered to offset the emissions of an equivalent amount of power that would otherwise be generated using the available array of power production techniques in a given region. Though it is usually referred to as a carbon offset, and is given in terms of carbon dioxide equivalents (CO_2e), it includes the offsetting of carbon dioxide and other recognized GHG emissions. A carbon offset for power production is developed by comparing the average GHG emission per unit of power production in this region with that of emissions for this project (none). The EPA provides estimates of average power plant emissions by region. An estimate of the carbon offset for Alternatives 1 and 2 was made with the EPA's eGRID2010 Version 1.1 Year 2007 GHG Annual Output Emission Rates using the annual non-baseload output emission rates. The carbon offsets for Alternatives 1 and 2 are presented in Table 4.2.7-1 and are given in units of metric tons of carbon dioxide equivalents per year (CO_2e).

Table 4.2.7-1: Carbon Offset Estimate for Project Alternatives

	Estimated Annual Power Production	GHG Offset Metric Tons of CO_2e/yr
Alternative 1	7256 MWH/yr	6060
Alternative 2	4608 MWH/yr	3850

5 LICENSING AND FEASIBILITY STUDY MILESTONES

5.1 Licensing and Feasibility Study Milestones

The licensing steps over the three year period covered by the Preliminary Permit fall under two broad categories - FERC licensing and feasibility assessment for hydropower development. The major milestones within each of these categories are summarized below:

Licensing - Major Milestones

- Completion of the Notice of Intent, Pre-Application Document and Request to use the Traditional Licensing Process[5] (September 1, 2011).
- Joint meeting and scoping with governmental agencies and other interested parties (December 1, 2011).
- Internal and external meetings and site visits.
- Development of Study Plans in consultation with governmental agencies and other interested parties (February 29, 2012).
- Conducting studies and developing reports according to the Study Plans (2012).
- Completion of a Draft License Application (due at FERC no later than 150 days prior to the Final License Application or approximately June 1, 2013).
- Completion of a Final License Application (due at FERC no later than November 1, 2013).

Feasibility Work - Major Milestones

- Development of a Preliminary Feasibility Study (August 2011).
- Development of a Detailed Feasibility Study (6 to 8 months from start date).

[5]The City is seeking approval from the FERC to use the Traditional Licensing Process in lieu of the Integrated Licensing Process to license the Project. For this study, it was assumed the FERC will grant the request.

6 ECONOMIC ANALYSIS

6.1 Falls Lake Dam Development

6.1.1 Opinion of Probable Construction Costs

The OPCC were developed based on the schematic design plans and turbine vendor budgetary quotes discussed in Section 2, engineering experience, and generally accepted cost estimating manuals. For Alternative 1, the powerhouse was sized and the turbine centerline elevations were set based on data for the existing Falls Lake Dam facilities and the dimensions of available turbines and generators appropriate for the proposed project. The powerhouse and gatehouse structures, penstock, trashrack and temporary siphon costs were based on internal information. The prices for valves and gates were from vendors. The turbine, generator and accessory electric equipment costs were from Voith. Transmission line costs were from internal information.

For Alternative 2, the modules were sized to fit into the space between the stop log grooves. The maximum size equipment that would fit was selected. Costs for the majority of the structural items including the module, trashrack, stairs, platforms and controls building were taken from R. S. Means Construction Cost Data ("Means") and internal information. The turbine and generator costs were from CHEC. The accessory electric equipment and transmission line costs are based on internal information. It should be noted the Chinese turbines are significantly less expensive than other manufacturers (less than half in some cases) but they do not have a long track record in the United States. CHEC turbines have been installed at a dozen hydroelectric facilities in the United States since 2001, and are currently being installed at the hydroelectric project at Jordan Lake in North Carolina.

A contingency of 25% has been added, based on the schematic level of design. Other costs include engineering, administration and construction services costs. Full time construction management costs for Alternative 1 and part time for Alternative 2 were added. The total OPCC are shown in **Table 6.1.2-1** and in more detail in **Appendix C**.

The following assumptions were made in developing the OPCC:

- Costs are referenced to July 1, 2011.
- A Mobilization/Demobilization cost of 10% was used.

6.1.2 Cost Analysis

Table 6.1.2-1 provides a summary of the generation estimates, OPCC, plant factor, and project cost for each alternative.

Table 6.1.2-1: Falls Lake Dam Development- Cost Analysis

Alternative / Vendor	No. of Turbines and Runner Diameter Size	Capacity (MW)	Avg. Annual Generation (MWH/yr)	OPCC ($2011) millions	Plant Factor (Avg Ann Gen/ Capacity x 8760 hrs/yr) (%)	*Cost of Capacity (OPCC/ Capacity) ($/MW) millions	**Cost of Energy (OPCC/ Avg Ann Gen. ($/MWH)
Alternative 1 Voith	2 – 1085 mm (3.6 ft)	1.90	7256	$28.4M	44%	$14.9M	$3,910
Alternative 2 CHEC	2 – 1250 mm (4.1 ft)	1.70	4608	$7.8M	31%	$4.6M	$1,700

* Rounded to $1,000. ** Rounded to $10.

6.1.3 Economic Analysis

Net Present Value Analysis - Input Variables

An economic analysis was conducted for each alternative (see **Appendix D** for the NPV spreadsheets). It should be noted that the licensing and feasibility study costs are considered sunk costs and therefore are not included in the NPV analysis. The following variables were included in the analyses:

- *Estimated Average Annual Generation* - the average annual generation was computed using the OASIS model and period of record. The average annual energy was assumed to be constant over the time horizon (50 years). The generation estimates used in the economic analysis are shown in Table 6.1.2-1. In any year, energy generation may be higher or lower than the estimated average.
- *Price of Power* – Progress Energy ("PE") is required under Section 210 of the Public Utility Regulatory Policies Act ("PURPA") to offer to purchase available electric energy and associated capacity from cogeneration and small power production facilities. For such energy and capacity purchases, PE is required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers[6]. The North Carolina Utilities Commission ("NCUC") utilizes the "Peaker Methodology" to establish PE's avoided cost energy and capacity rates.

[6] Small power producers include hydroelectric facilities contracting to sell 5 MW or less of capacity and associated energy.

According to the theory underlying the Peaker method, if a utility's generating system is operating at equilibrium (i.e., at the optimal point) the capital cost of a peaker plant plus the marginal energy cost of the system will produce the utility's avoided energy and capacity costs.

In Docket No. E-100, Sub 127, PE received NCUC approval to issue updated short-term and long-term (i.e., 15-years) energy and capacity avoided cost rates. The published long-term rates along with current Renewable Energy Certificate ("REC") price projections[7] and projected Greenhouse Gas ("GHG") emission price levels[8] formed the foundation of the first fourteen years (2012 – 2025) of BAI's preliminary reference price forecast. For the forecast years 2026 – 2035 BAI relied on future fuel trend price projections from the 2011 Energy Information Administration ("EIA") Annual Energy Outlook to derive the system marginal energy cost projection. PE has a plan to retire a portion of its existing coal fired generating plants and replace them with new natural gas fired plants. This will translate into the price of natural gas setting PE's marginal energy cost on a more frequent basis. For the forecast years 2036 – 2081 system marginal energy cost projections were based on future fuel cost projections derived from historical annual average growth rates. BAI further relied on historical annual average growth rates from 2012 – 2025 to develop projected avoided capacity rates, REC prices and GHG emission price levels for the forecast years 2026 – 2081. BAI's high and low electricity price forecasts are based on bandwidths around the mean reference case.

- Time Horizon – a 50-year time horizon was evaluated. The 50-year time horizon reflects the likely licensing term the City would receive. FERC typically issues 50-year license terms for newly constructed projects. Hydropower projects, if well-maintained, have a life of 70 years or more.
- Engineering and capital costs.
- Major maintenance items including a major turbine overhaul at year 25 and a generator re-wind at year 30.
- The annual O&M cost of $20/MWH was applied to the base case. This cost includes annual O&M and capital projects excluding the turbine overhaul and generator re-wind noted above.
- A 4.7% bond issue rate was used to cover the project's initial capital costs and the debt on the bond was assumed to be amortized over 30 years. *
- A 4.5% annual escalation rate was applied to engineering, capital costs, and future capital expenditures considered major maintenance.*

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[7] Duke Energy recently announced a plan to purchase Progress Energy and has established a standard offer price for Renewable Energy Certificates for the years 2012 – 2025. This price information was utilized in the development of the reference price forecast.

[8] Greenhouse Gas emission prices were derived from a recent Duke Energy CO2 price forecast through 2030.

- A 3.0% annual O&M escalation rate was applied to general annual O&M expense.*
- A 4.7% discount rate was used over a 50-year time horizon.*
- BAI developed a rate of 2.0% of the total project cost for the bond issuance charges.
- Construction is anticipated to start in 2016 for Alternative 2, approximately the same time as the FERC rules on the City's application. Design would occur during the 2014 to 2015 period.

* These percentages were confirmed or provided by the City.

Incentives

There are a variety of economic incentive programs theoretically available for hydroelectric development. The sunset provisions for these programs and the availability of funds in a competitive environment are in a state of flux. The programs are described below. To be conservative, no benefits from any of these programs have been applied to the economic analysis. The actual availability of funds and the ability of the City to procure them require more scrutiny than is warranted in this pre-feasibility assessment. To the extent the City is able to obtain such funds, the economics of the Project will be correspondingly improved.

For example, the Clean Renewable Energy Bonds ("CREBs") program awarded the entire Treasury allocation of $2.4 billion in CREBs in October 2009 and the Production Tax Credit ("PTC") program currently expires on December 31, 2013. Although Congress has been allocating additional funds and extending deadlines, it is not clear that these programs will remain available for this project's anticipated time frame.

The CREBs program was created under the Energy Tax Incentives Act of 2005, which added Section 54 to the Internal Revenue Code. The CREBs program is for public power providers. Entities receiving CREBs must use 100% of the proceeds for capital expenditures. CREBs were designed to be interest free by the federal government by extending a tax credit to investors in lieu of interest payments from the issuer. However, the 2010 HIRE Act changed CREBs from tax credit bonds to direct subsidy bonds. The issuer pays the investor a taxable coupon and receives a rebate from the U.S. Treasury.

Section 410 of the American Recovery and Reinvestment Act of 2009 increased State Energy Grants by $3.1 billion dollars. These funds are administrated by the DOE and are distributed through the existing State Energy Program.[9] North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), established by Senate Bill 3 in

[9] Authorized under the Energy Policy and Conservation Act of 1975.

August 2007, requires all investor-owned utilities in the state to supply 12.5% of 2020 retail electricity sales (in North Carolina) from eligible energy resources by 2021. Municipal utilities and electric cooperatives must meet a target of 10% renewables by 2018 and are subject to slightly different rules. In February 2008, the NCUC issued an order adopting final rules to implement the REPS.

Section 45 of the Internal Revenue Code of 1986 provides a PTC to owners or operators of electric generation facilities that produce electricity from qualified facilities. This credit applies to adding incremental power at existing hydroelectric facilities and new hydroelectric facilities to non-hydroelectric dams. Projects certified for the PTC receive a 1.1 cent per KW hour credit for ten years (the credit is adjusted for inflation). The pursuit of this alternative would require consideration of the City's municipal preference, and whether there are opportunities to partner with a taxpaying entity to take advantage of the PTC.

The Department of Treasury Section 1603 Tax Grant Program provides cash payment of up to 30 percent of equipment costs in place of the Investment Tax Credit ("ITC"). The project must be placed in service before January 1, 2014. A taxpayer eligible for the PTC can take the Section 48 ITC or the Section 1603 in lieu of the PTC.

Net Present Value Analysis

A baseline NPV analysis was conducted for each alternative. The baseline case is summarized below:

- Baseline Case- based on reference energy prices, a bond rate of 4.7%, a discount rate of 4.7%, and annual O&M costs of $20/MWH.

Table 6.1.3-1 lists by alternative, the NPV results for the baseline case.

Table 6.1.3-1: Falls Lake Dam Development Net Present Value Analysis

Alternative/ Vendor	Alternatives – No. of Turbines and Runner Diameter Size	Baseline NPV, 50-yr, with 30-yr Debt Retirement
Alternative 1 Voith	2 turbines total 2 – 1085 mm (3.6 ft)	-$16,815,618
Alternative 2 CHEC	2 turbines total 2 – 1250 mm (4.1 ft)	-$687,911

6.1.4 Conclusions

The large negative NPV for Alternative 1 shows that the downstream powerhouse alternative is not economically feasible over a 50-year term and 30-year debt retirement. For Alternative 2 – intake tower, the NPV is also negative, but the number is much less negative than for Alternative 1.

6.1.5 Sensitivity Analysis

Alternative 2 shows a small (relative to the initial capital investment) net negative NPV. However, this conclusion hinges on a number of assumptions for which precise values cannot be determined at this juncture. A sensitivity analysis will help determine which of these assumptions have the most influence on the project's NPV and how the outcome might change if their values differ from those assumed in this report. The assumptions that could influence the project's NPV include the estimates for the capital cost of the project, price of power, amount of power generated, escalation (inflation) of operations and maintenance costs, the bond issue rate, and the discount rate. A sensitivity analysis was done for a combined bond issue rate / discount rate (varied together) and the price of power. The results of this sensitivity analysis is shown below in Table 6.1.5-1

Table 6.1.5-1: Falls Lake Hydroelectric - Net Present Value Sensitivity Analysis

Energy Price Bond Issue Rate/ Discount Rate	Low Price	Reference Price	High Price
2.0%	$4,315,409	$7,763,041	$12,044,372
2.5%	$2,510,029	$5,348,152	$8,859,675
3.0%	$1,072,392	$3,420,110	$6,313,885
3.5%	-$73,768	$1,877,827	$4,273,993
4.0%		$642,231	$2,636,003
4.5%		-$348,722	$1,318,367
4.7% (base case)		**-$687,911**	$866,154
5.0%			$866,154
5.5%			-$598,851

The results indicate that both factors have a significant influence on whether or not the NPV of the project is positive as well as on the magnitude of the NPV. The Bond Issue Rate may be unlike many of the other factors insomuch as it could be fixed early on in the project and possibly even before the decision to construct the project is made.

6.2 Recommendations

Even though Alternative 2 is a marginal project based on the current best estimate of NPV, we recommend moving forward with more detailed evaluations and a more robust sensitivity analysis. Doing so will provide a better sense of the impact of the input parameters on the NPV result. In addition to the factors mentioned in 6.1.5 as having influence on the NPV of the project, renewable power incentives, if available, will have a positive impact on the project's NPV and were not included in this analysis.

Should the City elect to move forward with the project following the review of the sensitivity analysis results, the next step would be the preparation of a detailed feasibility study. By further refining the energy price forecast and construction costs, a more accurate NPV can be determined.

The detailed feasibility study would include the following tasks:

- Obtain as-built drawings of the intake tower and dam and prepare an accurate base plan. If as-built drawings are not available, survey of the intake tower, bridge and transmission line area would be needed.
- Obtain more detailed turbine and generator information from CHEC for the intake tower development.
- Obtain quotes from additional turbine vendors.
- Develop a detailed energy price forecast based on projected avoided cost energy prices and renewable energy credit values applied to the estimated energy output associated with the project.
- Prepare an interconnection study to determine whether the existing transmission system can accommodate the power generated by the hydro facility.
- Meet with the USACE to discuss their engineering and operating concerns, and determine what structural analyses they require.
- Review the loading restrictions on the bridge and intake tower, and determine how that affects construction.
- Have a structural engineer visit the site to conduct a visual inspection of the intake tower and to obtain information to assist in developing conceptual design plans.
- Prepare a detailed headloss analysis.
- Have an electrical engineer prepare a one-line diagram, conceptual layout of the electric control booth, transmission line and transformer, and cost estimate.
- Further review of renewable power generation incentives.

Once the information from the above scope items is completed, the following work can commence for the detailed feasibility study.

- Refine energy analyses based on new turbine/generator information and detailed headloss calculations.

- Develop conceptual site drawings based on detailed topographic and planimetric features and new turbine/generator layouts. The design will take into consideration the maintenance of equipment and constructability.
- Analyze the recommended development to ensure it meets the USACE operation plan and dam safety requirements.
- Perform detailed quantity takeoffs based on new conceptual plans.
- Revise cost opinion based on new quantity takeoffs and market prices.
- Update the economic analysis based on the updated energy price projections, cost estimates and generated energy. A sensitivity analysis for the detailed feasibility study NPV runs can be done, if desired, and the results compared with the results of the baseline condition to see which input parameters have the greatest impact on the NPV.
- Prepare a report presenting the proposed project layouts, the turbine/generator equipment information and cost quotes, the energy price projections, the energy analyses, the interconnection study results, the construction cost estimates, and the economic analyses.

Appendix A:
Licensing Schedule Following Filing of Final License Application

Schedule

The preliminary permit for the Falls Lake Dam Project was issued by the FERC in November 2010. The City has until November 2013 (3 years) to submit its Final License Application with the FERC. The tasks in Table 1 are required as part of the traditional licensing process[10] following the filing of the Final License Application. Approximate dates of completion are shown and were benchmarked against other traditional licensing processes. These dates are subject to change, as many of the tasks are in FERC's control. After filing the Final License Application, additional information requests ("AIRs") may be submitted by other parties, including non government organizations. If FERC finds that the AIRs are relevant, the City must address the issue, which could require field work and delay the overall process.

A key date is license issuance, which is projected to occur approximately two years after filing the Final License Application assuming there are no extensive AIRs. FERC typically requires construction of the hydropower facilities to begin within two years of license issuance and to be completed within four years of license issuance.

Table 1: Tasks Following Filing of License Application

Task	Approximate Schedule
File Final License Application and 401 Water Quality Certification Request	November 1, 2013 (firm date)
FERC issues "Notice of Application Tendered for filing with the Commission, Soliciting Additional Study Requests, and Establishing Procedural Schedule for Licensing and Deadline for Submission of Final Amendments" (within 14 days after filing the Final License Application)	November 15, 2013
Stakeholders must file any AIRs (no later than 60 days after filing the Final License Application)	January 1, 2013
FERC issues letter to Licensee outlining AIRs (regulations do not contain a date when FERC must issue this letter; benchmarked against another traditional licensing processes and assumed 130 days after the Stakeholders file AIRs)	May 10, 2014
Submit Response to AIRs (within 120 days of the date of FERC notifying the Licensee of the AIRs)	November 10, 2014

[10] The City is seeking approval from the FERC to use the Traditional Licensing Process in lieu of the Integrated Licensing Process to license the Project. For this study, it was assumed the FERC will grant the request.

Task	Approximate Schedule
NOTE: Although FERC requires 120 days to respond to AIRs, the schedule is commonly dictated by the number and extent of AIRs. For example, past experience indicates that upwards of 18 months can be required to complete the AIRs, if extensive field work is required.	
FERC issues letter informing public they are conducting the National Environmental Policy Act scoping for the Falls Lake Dam Project and issues the Scoping Document. FERC, in a separate filing, will provide notice soliciting scoping comments. (regulations do not contain a date when FERC must issue the Scoping Document; benchmarked against another traditional licensing process and assumed two months)	January 10, 2015
Comments due on Scoping Document (within 30 days of issuing Scoping Document)	February 10, 2015
FERC issues "Notice of Application Accepted for Filing, Soliciting Motions to Intervene and Protests, Ready for Environmental Analysis and Soliciting Comments, Recommendations, Terms and Conditions, and Fishway Prescriptions" (regulations do not contain a date when FERC must issue this notification; benchmarked against another traditional licensing process and assumed one month)	March 10, 2015
Reply comments on Application (within 105 days of the Notice of Application Accepted for Filing)	June 25, 2015
FERC issues Notice of Availability of Environmental Assessment (regulations do not contain a date when FERC must issue this notification; benchmarked against another traditional licensing process and assumed one month)	August 1, 2013
Comments due on Environmental Assessment (within 30 days of Notice of Availability of Environmental Assessment)	September 1, 2015
FERC issues Orders Issuing License (regulations do not contain a date when FERC must issue the license orders; benchmarked against another traditional licensing process and assumed four months following the due date for comments on the Environmental Assessment)	January 1, 2016
Article within FERC License will address start and completion of construction (typically, the article calls for commencement of construction two (2) years following License Issuance and completion of construction within four (4) years of license issuance)	Construction Start- 2016 Construction Complete- 2017

Appendix B:
Turbine Vendor Budgetary Quotes

- **Alternative 1 – Downstream Powerhouse - Voith**

- **Alternative 2 - Intake Tower - CHEC**

Rick Stewart

From:	Murtha, Brian [Brian.Murtha@Voith.com]
Sent:	Friday, June 24, 2011 6:11 PM
To:	John Huysentruyt
Cc:	rstewart@gomezandsullivan.com; Smith, Jeremy
Subject:	RE: Falls Dam - Feasibility Study
Attachments:	VH_Falls_Lake_2011-06-24.pdf

Voith

Hi John,
Below is some preliminary information and budgetary pricing for the Falls Lake Dam project. Please see the attached document for preliminary sizing and performance.

Option A - single large machine
Qty (1) 1590 [mm] horizontal Kaplan S-turbine with HPU
Qty (1) 2.75 [MVA] air cooled generator with brushless excitation
Qty (1) switchgear
Qty (1) neutral grounding cabinet

Package Price = $3.22 MUSD
Automation and Controls package = $0.9 MUSD

Option B - two small machines
Qty (2) 1095 [mm] horizontal Kaplan S-turbine with HPU
Qty (2) 1.35 [MVA] air cooled generator with brushless excitation
Qty (2) switchgear
Qty (2) neutral grounding cabinet

Package Price = $3.53 MUSD
Automation and Controls package = $1.1 MUSD

Included in the price:
- All project management, engineering, and transportation to job site is included.
- Coordination plant engineering is included.

Excluded from the price:
- Interconnecting wiring and piping is not included as this is very site specific. Neither is the routing design/layout included.
- Installation of the equipment is assumed to be by others. We can give you our daily rates for supervision and can also work up a number on installation if you are interested.
- Taxes are not included.

Other pricing notes:
- This pricing is given in today's market conditions, i.e. USD valuation and material price indices.
- Voith standard terms of sale apply.
- Neutral cash flow for the life of the project is assumed.

I hope this information is useful to you in your preliminary studies.

Don't hesitate to contact me with further questions.

Thank you and best regards,
-BAM

Appendix C:
Opinion of Probable Construction Costs for Falls Lake Dam Development

- **Alternative 1 – Downstream Powerhouse**

- **Alternative 2 – Intake Tower**

	Falls Lake Opinion of Probable Construction Cost Estimate	
	Alternative 1 - Downstream Powerhouse - Two 0.95 MW Turbines	
Item No.	Item	Cost
330	**Land and Land Rights[1]**	**$0**
	Mobilization/Demobilization (assume 10%)[2]	**$1,809,700**
331	**Powerplant Structures and Improvements**	
	Powerhouse Superstructure (includes misc. equipment,	$1,900,000
	and Powerhouse and Tailrace Excavation)	
	Diversion and Care of Water	$500,000
	331 Subtotal	**$2,400,000**
332	**Reservoir, Dam and Waterway**	
	Steel Tunnel Liner	$3,000,000
	Steel Penstock	$2,300,000
	Powerhouse Counterweight Valves	$670,000
	Bypass Gate Structure	$650,000
	Bypass Gate	$350,000
	Temp. Conservation Flow Siphon During Construct.	$2,220,000
	Trashracks	$150,000
	332 Subtotal	**$9,340,000**
333	**Waterwheel, Turbine and Generator[3]**	**$4,660,000**
334	**Accessory Electric Equipment[4]**	**$1,120,000**
353	**Substation and Switching Station Equipment**	**$490,000**
355/356	**Transmission Poles and Conductors**	**$87,000**
	Subtotal Direct Cost	**$19,906,700**
	Contingencies (25%)[5]	$4,977,000
	Total Direct Cost[6]	**$24,884,000**
	Engineering, Admin. and Part Time Constr.Services (10%)[6]	$2,488,000
	Full Time Construction Management	$1,000,000
	Total	**$28,372,000**

Notes

1 - The USACE requires an annual lease payment of $50 to $100 per acre for the occupied area of approximately 4 acres. This is a minimal cost and is not included in this OPCC.

2- The mobilization and demobilization costs are 10% of Item Nos. 331-356.

3 - Two 0.95 MW 1085 mm horizontal S style Kaplan axial flow turbine and two generators.

4 - Control panels, programmable logic controller and hydraulic power unit.

5 - The contingency is 25% of all items. Rounded to $1000.

6 - Rounded to $1000.

Falls Lake Opinion of Probable Construction Cost Estimate		
Alternative 2 - Intake Tower Turbines - Two 0.85 MW Turbines		
Item No.	Item	Cost
330	**Land and Land Rights[1]**	**$0**
	Mobilization/Demobilization (assume 10%)[2]	**$500,850**
331	**Powerplant Structures and Improvements**	
	Steel Frames for Turbine (2)	$232,000
	1/4" Steel Plate	$156,000
	Steel Frame for Deck and Support Structure	$188,000
	Grating	$185,000
	Railing	$45,000
	Trashracks	$210,000
	Controls Building	$30,000
	Support Frame for Controls Bldg. & Floor Framing	$22,000
	Lifting Beam (2)	$11,500
	Frame Support And Lifting Doggs	$24,000
	Spiral Stairs	$25,000
	Hydraulic Actuators (2)	$75,000
	Spill Gates (4), Stems and Hydraulic Cylinders	$150,000
	331 Subtotal	**$1,353,500**
332	**Reservoir, Dam and Waterway**	
	Concrete Demolition (Top of Flume)	$350,000
	332 Subtotal	**$350,000**
333	**Waterwheel, Turbine and Generator[3]**	**$2,230,000**
334	**Accessory Electric Equipment[4]**	**$430,000**
353	**Substation and Switching Station Equipment**	**$480,000**
355/356	**Transmission Poles and Conductors**	**$165,000**
	Subtotal Direct Cost	**$5,509,350**
	Contingencies (25%)[5]	$1,377,000
	Total Direct Cost[6]	**$6,886,000**
	Engineering, Admin. and Part Time Constr.Services (10%)[6]	$689,000
	Half Time Construction Management	$250,000
	Total	**$7,825,000**

Notes

1 - The USACE requires an annual lease payment of $50 to $100 per acre for the occupied area of approximately 2 acres. This is a minimal cost and is not included in this OPCC.

2- The mobilization and demobilization costs are 10% of Item Nos. 331-356.

3 - Two 0.85 MW 1250 mm vertical Kaplan turbines and two generators and shafts.

4 - Control panels, programmable logic controller, switchgear, station service equipment and hydraulic power unit.

5 - The contingency is 25% of all items. Rounded to $1000.

6 - Rounded to $1000.

Appendix D:
Net Present Value Analyses

- **Alternative 1 – Downstream Powerhouse**
    - **Base Case, 50-year, Voith**

- **Alternative 2 – Intake Tower**
    - **Base Case, 50-year, CHEC**

7/6/2011			Bond Issuance Rate	4.76%				
		2011 Net Present Value of Project		[illegible]		Base Case - Reference Energy Price, Annual O&M $20/MWH, 35 cfs minimum flow		
Falls Lake Hydro Project								
Site Name		Alternative 1 - Downstream Powerhouse				Falls Lake 1.9 MW 2 turbines (50 year, 4.76% discount rate, 4.50% escalation rate, 3.0% Annual O&M escalation rate)		

Cost Base Year	Year Spent	Generation Revenue Total[1]			Engineering and Construction Total[1]					O and M[4] Major Maintenance		O and M[4] Annual Operation and Maintenance		O and M[4] O&M Total		Annual Cash Flows
		Generation (MWH)	Progress Energy Avoided Energy Costs - Reference Forecast ($/MWH)	Nominal Cash Flow (year generated $)	Base Year Cost[2]	Nominal Cash Flow (year spent $)	Accumulated Total	Interest on Unpaid Amount	Bond Payment	Base Year Cost[3]	Nominal Cash Flow (year spent $)	Base Year Cost[3]	Nominal Cash Flow (year spent $)	Base Year Cost	Nominal Cash Flow (year spent $)	
2011	2011			$0	$0	$0	$0	$0	$0		$0		$0		$0	$0
2011	2012			$0	$0	$0	$0	$0	$0		$0		$0		$0	$0
2011	2013			$0	$0	$0	$0	$0	$0		$0		$0		$0	$0
2011	2014			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2015			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2016			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2017			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2018			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2019			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2020			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2021	7256	[illegible]	[illegible]	Issue Bond for Total Amount (See Separate Worksheet)				[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2022	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2023	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2024	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2025	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2026	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2027	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2028	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2029	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2030	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2031	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2032	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2033	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2034	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2035	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2036	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2037	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2038	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2039	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2040	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2041	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2042	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2043	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2044	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2045	7256	[illegible]	[illegible]					[illegible]	[illegible]	[illegible]	$145,120	[illegible]	[illegible]	[illegible]	[illegible]
2011	2046	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2047	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2048	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2049	7256	[illegible]	[illegible]					[illegible]		$0	$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2050	7256	[illegible]	[illegible]					[illegible]	[illegible]	[illegible]	$145,120	[illegible]	[illegible]	[illegible]	[illegible]
2011	2051	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2052	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2053	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2054	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2055	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2056	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2057	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2058	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2059	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2060	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2061	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2062	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2063	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2064	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2065	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2066	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2067	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2068	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2069	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
2011	2070	7256	[illegible]	[illegible]								$145,120	[illegible]	$145,120	[illegible]	[illegible]
															Total	[illegible]
														2,011	NPV Of Cash Flows	[illegible]

NOTES:

1) Dollars are referenced to July 1, 2011.

2) These costs are from the OPCC tables. They are the engineering and capital costs divided by the number of years when the costs are spent. The yearly amounts are rounded up to the nearest $1000, and therefore the total amounts do not exactly equal the OPCC total.

3) Turbine major overhaul at year 25 and generator re-wind at year 30.

4) Average Annual Power Plant Operating Expense is $20/MWH.

Page 1

DEBT SERVICE EXPENSE OF NEW BOND ISSUANCE

Line	Description	Amount (a)
1	Revenue bond issuance amount	$44,255,765
2	Assumed Issuance Costs (2% of bond issue)	$885,115
3	Total Bond Issuance Amount	$45,140,880
4	Term of Bond (Years)	30
5	Interest Rate	4.70%
6	Calculated Annual Debt Service Expense	$2,836,830

Year	Payment	Interest	Principal Repayment	Balance
0				$ 45,140,880
1	$2,836,830	$ 2,121,621	$ 715,209	$ 44,425,672
2	$2,836,830	$ 2,088,007	$ 748,824	$ 43,676,848
3	$2,836,830	$ 2,052,812	$ 784,018	$ 42,892,829
4	$2,836,830	$ 2,015,963	$ 820,867	$ 42,071,962
5	$2,836,830	$ 1,977,382	$ 859,448	$ 41,212,514
6	$2,836,830	$ 1,936,988	$ 899,842	$ 40,312,672
7	$2,836,830	$ 1,894,696	$ 942,135	$ 39,370,537
8	$2,836,830	$ 1,850,415	$ 986,415	$ 38,384,122
9	$2,836,830	$ 1,804,054	$ 1,032,777	$ 37,351,346
10	$2,836,830	$ 1,755,513	$ 1,081,317	$ 36,270,029
11	$2,836,830	$ 1,704,691	$ 1,132,139	$ 35,137,890
12	$2,836,830	$ 1,651,481	$ 1,185,349	$ 33,952,540
13	$2,836,830	$ 1,595,769	$ 1,241,061	$ 32,711,480
14	$2,836,830	$ 1,537,440	$ 1,299,391	$ 31,412,089
15	$2,836,830	$ 1,476,368	$ 1,360,462	$ 30,051,627
16	$2,836,830	$ 1,412,426	$ 1,424,404	$ 28,627,223
17	$2,836,830	$ 1,345,479	$ 1,491,351	$ 27,135,872
18	$2,836,830	$ 1,275,386	$ 1,561,444	$ 25,574,428
19	$2,836,830	$ 1,201,998	$ 1,634,832	$ 23,939,596
20	$2,836,830	$ 1,125,161	$ 1,711,669	$ 22,227,926
21	$2,836,830	$ 1,044,713	$ 1,792,118	$ 20,435,809
22	$2,836,830	$ 960,483	$ 1,876,347	$ 18,559,461
23	$2,836,830	$ 872,295	$ 1,964,535	$ 16,594,926
24	$2,836,830	$ 779,962	$ 2,056,869	$ 14,538,057
25	$2,836,830	$ 683,289	$ 2,153,542	$ 12,384,516
26	$2,836,830	$ 582,072	$ 2,254,758	$ 10,129,757
27	$2,836,830	$ 476,099	$ 2,360,732	$ 7,769,026
28	$2,836,830	$ 365,144	$ 2,471,686	$ 5,297,340
29	$2,836,830	$ 248,975	$ 2,587,855	$ 2,709,484
30	$2,836,830	$ 127,346	$ 2,709,484	$ (0)

7/6/2011 Bond Issuance Rate [illegible]

2011 Net Present Value of Project [illegible] Base Case - Reference Energy Price, Annual O&M $28/MWH, 85 cfs minimum flow

Falls Lake Hydro Project

Site Name		Alternative 2 - Intake Tower			Falls Lake 1.70 MW - 2 turbines (50 year, 4.78% discount rate, 4.50% escalation rate, 3.8% Annual O&M escalation rate)											
Cost Base Year	Year Spent	Generation Revenue Total[1]			Engineering and Construction Total[1]					O and M[4]						Annual Cash Flows
										Major Maintenance		Annual Operation and Maintenance		O&M Total		
		Generation (MWH)	Progress Energy Avoided Energy Costs - Reference Forecast ($/MWH)	Nominal Cash Flow (year generated $)	Base Year Cost[2]	Nominal Cash Flow (year spent $)	Accumulated Total	Interest on Unpaid Amount	Bond Payment	Base Year Cost[3]	Nominal Cash Flow (year spent $)	Base Year Cost[4]	Nominal Cash Flow (year spent $)	Base Year Cost	Nominal Cash Flow (year spent $)	
2011	2011			$0	$0	$0	$0	$0	$0		$0		$0		$0	$0
2011	2012			$0	$0	$0	$0	$0	$0		$0		$0		$0	$0
2011	2013			$0	$0	$0	$0	$0	$0		$0		$0		$0	$0
2011	2014			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2015			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2016			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2017			$0	[illegible]	[illegible]	[illegible]	[illegible]	$0		$0		$0		$0	$0
2011	2018	[illegible]	[illegible]	[illegible]	Issue Bond for Total Amount (See Separate Worksheet)				[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2019	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2020	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2021	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2022	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2023	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2024	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2025	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2026	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2027	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2028	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2029	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2030	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2031	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2032	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2033	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2034	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2035	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2036	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2037	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2038	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2039	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2040	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2041	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2042	[illegible]	[illegible]	[illegible]					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2043	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2044	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2045	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2046	[illegible]	[illegible]	[illegible]					[illegible]		$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2047	[illegible]	[illegible]	[illegible]					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2048	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2049	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2050	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2051	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2052	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2053	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2054	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2055	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2056	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2057	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2058	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2059	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2060	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2061	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2062	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2063	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2064	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2065	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2066	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	2067	[illegible]	[illegible]	[illegible]								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
															Total	[illegible]
														2,011 NPV Of Cash Flows		[illegible]

NOTES:

1) Dollars are referenced to July 1, 2011.

2) These costs are from the OPCC tables. They are the engineering and capital costs divided by the number of years when the costs are spent. The yearly amounts are rounded up to the nearest $1000, and therefore the total amounts do not exactly equal the OPCC total.

3) Turbines major overhaul at year 25 and generator re-wind at year 35.

4) Average Annual Power Plant Operating Expense is $28/MWH.

DEBT SERVICE EXPENSE OF NEW BOND ISSUANCE

Line	Description	Amount
		(a)
1	Revenue bond issuance amount	$10,684,307
2	Assumed Issuance Costs (2% of bond issue)	$213,686
3	Total Bond Issuance Amount	$10,897,993
4	Term of Bond (Years)	30
5	Interest Rate	4.70%
6	Calculated Annual Debt Service Expense	$684,873

Year	Payment	Interest	Principal Repayment	Balance
0				$ 10,897,993
1	$684,873	$ 512,206	$ 172,667	$ 10,725,326
2	$684,873	$ 504,090	$ 180,782	$ 10,544,543
3	$684,873	$ 495,594	$ 189,279	$ 10,355,264
4	$684,873	$ 486,697	$ 198,176	$ 10,157,089
5	$684,873	$ 477,383	$ 207,489	$ 9,949,600
6	$684,873	$ 467,631	$ 217,242	$ 9,732,358
7	$684,873	$ 457,421	$ 227,452	$ 9,504,906
8	$684,873	$ 446,731	$ 238,142	$ 9,266,764
9	$684,873	$ 435,538	$ 249,335	$ 9,017,429
10	$684,873	$ 423,819	$ 261,054	$ 8,756,376
11	$684,873	$ 411,550	$ 273,323	$ 8,483,053
12	$684,873	$ 398,703	$ 286,169	$ 8,196,884
13	$684,873	$ 385,254	$ 299,619	$ 7,897,264
14	$684,873	$ 371,171	$ 313,701	$ 7,583,563
15	$684,873	$ 356,427	$ 328,445	$ 7,255,118
16	$684,873	$ 340,991	$ 343,882	$ 6,911,236
17	$684,873	$ 324,828	$ 360,045	$ 6,551,191
18	$684,873	$ 307,906	$ 376,967	$ 6,174,225
19	$684,873	$ 290,189	$ 394,684	$ 5,779,540
20	$684,873	$ 271,638	$ 413,234	$ 5,366,306
21	$684,873	$ 252,216	$ 432,656	$ 4,933,650
22	$684,873	$ 231,882	$ 452,991	$ 4,480,659
23	$684,873	$ 210,591	$ 474,282	$ 4,006,377
24	$684,873	$ 188,300	$ 496,573	$ 3,509,804
25	$684,873	$ 164,961	$ 519,912	$ 2,989,892
26	$684,873	$ 140,525	$ 544,348	$ 2,445,544
27	$684,873	$ 114,941	$ 569,932	$ 1,875,612
28	$684,873	$ 88,154	$ 596,719	$ 1,278,893
29	$684,873	$ 60,108	$ 624,765	$ 664,129
30	$684,873	$ 30,744	$ 664,129	$ (0)

Appendix E:
Preliminary 70-Year Electric Price Forecast
Progress Energy Avoided Energy Costs

Preliminary 70-Year Electric Price Forecast

Progress Energy Avoided Energy Costs

(Energy, Capacity, GHG, REC)

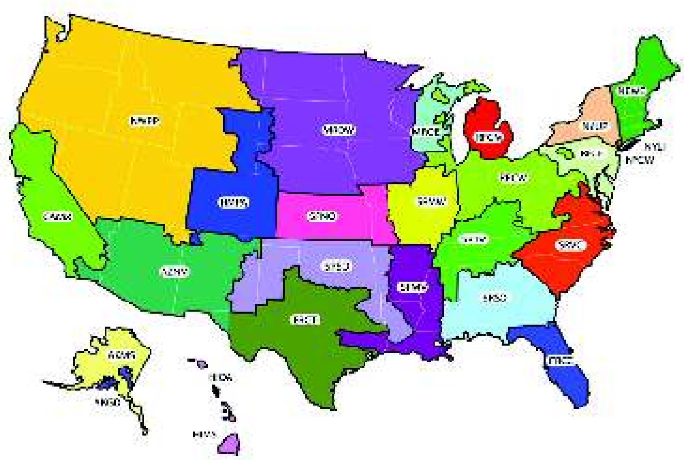
	Real 2011 $/MWh			Nominal $/MWh		
Year	Reference Price Forecast	High Price Forecast	Low Price Forecast	Reference Price Forecast	High Price Forecast	Low Price Forecast
2012	$ 68.76	$ 69.12	$ 68.40	$ 70.97	$ 71.34	$ 70.60
2013	$ 69.52	$ 70.26	$ 68.80	$ 73.03	$ 73.80	$ 72.27
2014	$ 70.04	$ 71.15	$ 68.94	$ 75.18	$ 76.37	$ 73.99
2015	$ 74.53	$ 76.05	$ 73.04	$ 81.71	$ 83.37	$ 80.08
2016	$ 75.22	$ 77.15	$ 73.35	$ 84.54	$ 86.70	$ 82.44
2017	$ 75.96	$ 78.31	$ 73.70	$ 87.46	$ 90.16	$ 84.86
2018	$ 76.75	$ 79.53	$ 74.08	$ 90.48	$ 93.76	$ 87.33
2019	$ 77.58	$ 80.82	$ 74.50	$ 93.60	$ 97.51	$ 89.88
2020	$ 78.47	$ 82.18	$ 74.96	$ 96.82	$ 101.40	$ 92.50
2021	$ 79.67	$ 83.89	$ 75.72	$ 100.14	$ 105.45	$ 95.17
2022	$ 80.63	$ 85.37	$ 76.23	$ 103.56	$ 109.65	$ 97.91
2023	$ 81.64	$ 86.92	$ 76.78	$ 107.11	$ 114.03	$ 100.73
2024	$ 82.69	$ 88.54	$ 77.36	$ 110.77	$ 118.59	$ 103.61
2025	$ 86.12	$ 92.57	$ 80.27	$ 117.33	$ 126.12	$ 109.36
2026	$ 87.04	$ 93.95	$ 80.80	$ 121.37	$ 131.01	$ 112.68
2027	$ 91.24	$ 98.70	$ 84.55	$ 129.75	$ 140.36	$ 120.23
2028	$ 93.93	$ 101.91	$ 86.80	$ 136.16	$ 147.72	$ 125.82
2029	$ 94.48	$ 102.76	$ 87.10	$ 139.99	$ 152.25	$ 129.06
2030	$ 97.46	$ 106.10	$ 89.80	$ 147.09	$ 160.12	$ 135.53
2031	$ 98.85	$ 108.02	$ 90.75	$ 152.36	$ 166.49	$ 139.87
2032	$ 100.22	$ 109.99	$ 91.63	$ 157.68	$ 173.06	$ 144.17
2033	$ 101.43	$ 111.77	$ 92.38	$ 162.84	$ 179.45	$ 148.32
2034	$ 103.18	$ 114.24	$ 93.55	$ 169.44	$ 187.60	$ 153.63
2035	$ 104.82	$ 116.67	$ 94.58	$ 175.98	$ 195.88	$ 158.79
2036	$ 105.59	$ 118.00	$ 94.92	$ 181.00	$ 202.26	$ 162.71
2037	$ 106.82	$ 119.86	$ 95.65	$ 186.95	$ 209.77	$ 167.40
2038	$ 107.41	$ 120.97	$ 95.85	$ 191.93	$ 216.17	$ 171.27
2039	$ 108.02	$ 122.11	$ 96.05	$ 197.07	$ 222.78	$ 175.24
2040	$ 109.56	$ 124.42	$ 97.01	$ 204.09	$ 231.76	$ 180.71
2041	$ 110.23	$ 125.64	$ 97.26	$ 209.64	$ 238.96	$ 184.98
2042	$ 110.90	$ 126.89	$ 97.52	$ 215.35	$ 246.40	$ 189.36
2043	$ 112.32	$ 129.07	$ 98.37	$ 222.69	$ 255.88	$ 195.02
2044	$ 113.29	$ 130.72	$ 98.84	$ 229.33	$ 264.60	$ 200.06
2045	$ 114.02	$ 132.07	$ 99.12	$ 235.66	$ 272.95	$ 204.86
2046	$ 115.49	$ 134.35	$ 99.98	$ 243.70	$ 283.50	$ 210.98
2047	$ 116.22	$ 135.73	$ 100.25	$ 250.39	$ 292.42	$ 215.98
2048	$ 117.24	$ 137.50	$ 100.73	$ 257.88	$ 302.46	$ 221.57
2049	$ 118.81	$ 139.97	$ 101.65	$ 266.83	$ 314.35	$ 228.30
2050	$ 119.61	$ 141.46	$ 101.96	$ 274.26	$ 324.38	$ 233.80
2051	$ 120.44	$ 143.01	$ 102.31	$ 281.98	$ 334.82	$ 239.52
2052	$ 122.42	$ 146.07	$ 103.51	$ 292.63	$ 349.15	$ 247.44
2053	$ 123.29	$ 147.69	$ 103.87	$ 300.89	$ 360.44	$ 253.49
2054	$ 124.16	$ 149.33	$ 104.22	$ 309.38	$ 372.10	$ 259.69
2055	$ 125.92	$ 152.14	$ 105.25	$ 320.37	$ 387.07	$ 267.76
2056	$ 127.13	$ 154.28	$ 105.82	$ 330.23	$ 400.75	$ 274.88
2057	$ 128.03	$ 156.01	$ 106.18	$ 339.56	$ 413.76	$ 281.59
2058	$ 129.87	$ 158.99	$ 107.23	$ 351.67	$ 430.51	$ 290.35
2059	$ 130.80	$ 160.79	$ 107.58	$ 361.61	$ 444.52	$ 297.43
2060	$ 132.05	$ 163.07	$ 108.16	$ 372.75	$ 460.29	$ 305.31
2061	$ 132.99	$ 164.92	$ 108.51	$ 383.28	$ 475.29	$ 312.72
2062	$ 134.43	$ 167.46	$ 109.23	$ 395.57	$ 492.74	$ 321.40
2063	$ 135.40	$ 169.38	$ 109.59	$ 406.78	$ 508.86	$ 329.24
2064	$ 136.73	$ 171.83	$ 110.19	$ 419.40	$ 527.07	$ 338.00
2065	$ 137.72	$ 173.82	$ 110.56	$ 431.33	$ 544.37	$ 346.26
2066	$ 139.26	$ 176.56	$ 111.32	$ 445.29	$ 564.56	$ 355.95
2067	$ 140.28	$ 178.63	$ 111.70	$ 457.99	$ 583.17	$ 364.67
2068	$ 141.70	$ 181.27	$ 112.33	$ 472.31	$ 604.23	$ 374.44
2069	$ 142.75	$ 183.41	$ 112.73	$ 485.83	$ 624.22	$ 383.64
2070	$ 144.38	$ 186.37	$ 113.52	$ 501.69	$ 647.58	$ 394.45
2071	$ 145.47	$ 188.59	$ 113.92	$ 516.09	$ 669.08	$ 404.16
2072	$ 146.97	$ 191.44	$ 114.59	$ 532.35	$ 693.45	$ 415.07
2073	$ 148.09	$ 193.75	$ 115.00	$ 547.68	$ 716.55	$ 425.31
2074	$ 149.81	$ 196.93	$ 115.83	$ 565.70	$ 743.59	$ 437.38
2075	$ 150.97	$ 199.32	$ 116.26	$ 582.04	$ 768.45	$ 448.20
2076	$ 152.56	$ 202.39	$ 116.96	$ 600.51	$ 796.66	$ 460.37
2077	$ 153.75	$ 204.88	$ 117.39	$ 617.90	$ 823.38	$ 471.79
2078	$ 155.58	$ 208.30	$ 118.26	$ 638.38	$ 854.71	$ 485.26
2079	$ 156.80	$ 210.88	$ 118.71	$ 656.93	$ 883.47	$ 497.33
2080	$ 158.49	$ 214.18	$ 119.44	$ 677.91	$ 916.14	$ 510.91
2081	$ 159.74	$ 216.85	$ 119.90	$ 697.64	$ 947.05	$ 523.62

Appendix F:
eGRID2010 Version 1.1 Year 2007
GHG Annual Output Emission Rates

eGRID2010 Version 1.1 Year 2007 GHG Annual Output Emission Rates

Annual total output emission rates for greenhouse gases (GHGs) can be used as default factors for estimating GHG emissions from electricity use when developing a carbon footprint or emission inventory. Annual non-baseload output emission rates should not be used for those purposes, but can be used to estimate GHG emissions reductions from reductions in electricity use.

eGRID subregion acronym	eGRID subregion name	Annual total output emission rates: Carbon dioxide (CO_2) (lb/MWh)	Annual total output emission rates: Methane (CH_4) (lb/GWh)	Annual total output emission rates: Nitrous oxide (N_2O) (lb/GWh)	Annual non-baseload output emission rates: Carbon dioxide (CO_2) (lb/MWh)	Annual non-baseload output emission rates: Methane (CH_4) (lb/GWh)	Annual non-baseload output emission rates: Nitrous oxide (N_2O) (lb/GWh)
AKGD	ASCC Alaska Grid	1,284.72	27.11	7.44	1,363.19	34.99	6.95
AKMS	ASCC Miscellaneous	535.73	22.65	4.48	1,462.30	61.68	12.18
AZNM	WECC Southwest	1,252.61	18.80	16.57	1,211.84	20.56	9.31
CAMX	WECC California	681.01	28.29	6.23	1,045.30	39.42	4.74
ERCT	ERCOT All	1,252.57	17.76	13.99	1,096.19	19.69	5.63
FRCC	FRCC All	1,220.11	41.19	15.25	1,286.41	43.40	11.50
HIMS	HICC Miscellaneous	1,343.82	135.15	21.71	1,645.57	122.94	21.33
HIOA	HICC Oahu	1,620.76	91.05	20.89	1,630.89	106.18	18.52
MROE	MRO East	1,692.32	28.79	29.05	1,905.18	35.25	29.98
MROW	MRO West	1,722.67	28.97	29.19	1,988.69	53.59	32.98
NEWE	NPCC New England	827.95	76.98	15.20	1,204.91	60.69	13.41
NWPP	WECC Northwest	858.79	16.34	13.64	1,279.58	43.31	15.75
NYCW	NPCC NYC/Westchester	704.80	26.22	3.35	1,234.06	37.65	4.88
NYLI	NPCC Long Island	1,418.74	90.50	13.10	1,397.80	44.08	6.99
NYUP	NPCC Upstate NY	683.27	17.41	9.90	1,384.20	31.55	16.19
RFCE	RFC East	1,059.32	27.40	17.03	1,671.96	33.29	22.19
RFCM	RFC Michigan	1,651.11	32.55	27.79	1,803.64	32.09	27.33
RFCW	RFC West	1,551.52	18.37	25.93	1,982.05	24.30	31.48
RMPA	WECC Rockies	1,906.06	23.63	28.89	1,554.38	23.17	16.45
SPNO	SPP North	1,798.71	21.22	29.20	1,958.22	25.40	27.75
SPSO	SPP South	1,624.03	24.52	22.42	1,435.24	25.03	13.14
SRMV	SERC Mississippi Valley	1,004.10	21.80	11.15	1,171.05	28.25	6.91
SRMW	SERC Midwest	1,779.27	20.57	29.60	1,945.66	24.02	29.69
SRSO	SERC South	1,495.47	23.64	24.57	1,551.05	28.50	21.69
SRTV	SERC Tennessee Valley	1,540.85	19.87	25.48	1,917.25	25.98	30.05
SRVC	SERC Virginia/Carolina	1,118.41	22.26	19.08	1,661.11	38.01	24.51
U.S.		**1,293.05**	**25.07**	**19.64**	**1,520.21**	**32.23**	**18.41**



This is a representational map; many of the boundaries shown on this map are approximate because they are based on companies, not on strictly geographical boundaries.

http://www.epa.gov/egrid